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ASSURANCE FOR INITIATION AND IMPLEMENTATION OF THE NIGERIAN TRANSITIONAL ELECTRICITY MARKET

Action Plan to Address Gaps for Initiation of TEM

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Action Plan to Address Gaps for Initiation of TEM

November 1, 2013

Prepared by Nexant, Inc. under Contract No. NARUC-2013-255-EPPAOO.

Report Submitted to:

Nigerian Electricity Regulatory Commission (NERC)

National Association of Regulatory Utility Commissioners (NARUC)

CONTENTS

1 EXECUTIVE SUMMARY

1.1 Project Overview

Nexant, Inc. has been retained by the National Association of Utility Regulatory Commissioners (NARUC) to provide consulting services to the Nigerian Electricity Regulatory Commission for the Assurance for Initiation and Implementation of the Nigerian Transitional Electricity Market (TEM). The project is sponsored by USAID.

The objective of the assignment is to conduct an independent assessment of the readiness of key entities in the Nigerian Electricity Supply Industry to ensure seamless commencement and implementation of the TEM. The scope of work covers the following main activities:

- Assess status of attainment of Conditions Precedent to initiation of TEM, and any gaps in the attainment of CPs;
- Develop Action Plan to remediate gaps; and
- Develop Action Plan to initiate TEM.

Areas considered in this assignment include:

- Metering;
- Market Settlement Procedures and System;
- SCADA;
- Contracts and commercial arrangements;
- Payments arrangements; and
- Applicable rules and regulations (Market Rules, Grid Code, NERC orders, etc).

The purpose of this Report is to provide an assessment of the requirements for TEM in the above areas, evaluate the current status of attainment of such requirements, identify the gaps, and recommend action plans to address the gaps during the Interim Period prior to declaration of TEM.

1.2 Summary of Gaps for Initiation of TEM

The following gaps need to be addressed prior to declaration of TEM:

- Current practices used by SO for tracking and determining generator Available Capacity are wholly inadequate and erroneous. The process is deficient in multiple areas and these problems must be addressed prior to TEM to ensure that the market invoices are correct.
- Another critical issue to be addressed prior to TEM is ensuring the financial security of MO and NBET in the event of DisCo default on payment obligations.

The following gaps are considered serious and must be addressed on an urgent basis to ensure proper functioning of TEM, but are not viewed as critical enough to hold up the declaration of TEM. However, while these gaps persist, the market is likely to operate inefficiently and with a high volume of complaints and disputes.

1.2.1 MO Responsibilities

- Automatic Meter Reading (AMR) data collection system for remote access to the information stored in the Trading Point meters is yet to be fully implemented.
- Contractor needs to complete project to upgrade storage capacity of EDMI meters installed at Trading Points.
- The framework for the adjustment of Trading Point meter readings for losses due the installation of the commercial meters at locations different from the connection points or the exact boundary points needs to be developed to enable the MO to apply the adjustments in the calculation of the Settlement Quantities.
- Substation consumption meters are not working or nonexistent, and are typically not read or tracked.
- Many locations provide inadequate physical security for Trading Point meters.
- Rules and procedures for reading meters are not followed.
- MO telecommunications and IT infrastructure for meter data collection and management require significant and extensive improvements.
- At present, the MO/SO does not have a Contract Register. The MO has not attempted to harmonize the current logic for calculation of settlement quantities for the GenCos with the formulae for calculating the contracted energy and Available Capacity as specified in the PPAs. The SO/MO may not be cognizant of operating requirements contained in the PPAs.
- MO settlement system architecture should be significantly improved in terms of inter-operability, security and automation. MO ONEM web portal is underdeveloped and inadequate.
- Provision for online handling of complaints is not yet operational. MO is not adequately prepared to handle a possible onslaught of complaints and disputes regarding settlement quantities when TEM is initiated.
- Rudimentary tracking of payments and nonpayments using spreadsheets is wholly inadequate for TEM. MO lacks capacity to monitor on an ongoing basis the bank transactions associated with market payments.
- Settlement system fails to integrate with either the MO's own finance accounting system or a payment agent's system.
- None of the DisCos has posted the required Security Cover to MO and NBET to mitigate the risk of nonpayment.

1.2.2 SO Responsibilities

- Communications and data exchange interfaces between SO and Market Participant are inadequate.
- Non-adherence to rules and procedures for submission of data from GenCo to SO.
- No written confirmation from NCC of operating instructions to Market Participants, only verbal; neither is reception confirmed in writing by the receiving end.

- Nonexistent or inadequate systems in place by SO to record, track, and confirm with the Market Participant and transmit to the MO how much of the hourly operational data is required to calculate GenCo/IPP Available Capacity.
- SO has no way to independently verify GenCo reported hourly meter readings.
- No daily reconciliation of or agreement on contract quantities between SO and Market Participants.
- The actual deliveries to DisCos do not meet the load allocation in accordance with share percentages in Vesting Contracts for various technical reasons and inadequate SO and DisCo process controls.
- DisCo load centres regularly violate their allocations.
- There is a lack of communication between SO and DisCo on load allocations.
- There is a lack of automation and computerization of data collection for tracking contract quantities.
- Some SO staff are not conversant with Grid Code and Market Rules.
- SCADA and EMS systems for system operations are inadequate and at present out of commission. Training of operations and maintenance teams on SCADA/EMS is greatly needed.
- Only a few of the power plants provide spinning reserves and black start. Other power plants have to be encouraged to join in the provision of such services.
- Operations Planning group does not produce a schedule of ancillary services.
- The system is often operated out of compliance with reliability and security requirements.

1.2.3 NBET Responsibilities

- NBET has developed the basic design for its settlement process, but as yet it is untested.
- There is a lack of coordination between NBET and MO regarding planning for the settlement process under TEM, including processes, systems, inter-operability and interfaces.
- Successor Company GenCos need to adopt the practice of submitting monthly invoices that can be vetted by NBET.
- NBET needs to complete its procurement for an authorized payment agent to directly handle and oversee receipts from DisCos and payments to GenCos and DisCos.
- NBET IT and telecommunications are still under development and not yet adequate for TEM.
- NBET systems and processes for accounting for market transactions are still under development.
- NBET's contracts with DisCos and GenCos are not yet effective.

1.3 Action Plan to Address Gaps

The following table shows the gaps that need to be closed for TEM, the recommended actions to address the gaps and institutional responsibilities for required actions.

Item	Gap for TEM	Action Plan
Compliance with Metering Requirements at Trading Points Responsibility: MO	99% of Trading Points in the Nigerian Electricity Market have been metered. The following issues remain to be addressed (or derogations granted): • Some meters are not located at the trading point as specified in rules. This can be addressed using loss factor adjustment for determination of contract quantities, or moving the meters. • Missing check meters at many locations, or location of check meter is different from main meter. • Need to complete program to upgrade meters so that Data Registers have adequate storage capacity. • Instances of erroneous double metering of GenCos. • Trading Points for some NIPP GenCos are yet to be metered.	• Locate metering system for all generator trading points as close as possible to the HV side of the step up unit transformer • Check meters should be installed at all the trading points by the DisCos and GenCos • The manufacturers of the EDMI meters installed at TPs and check points should complete the upgrading of the meters to adequately store data • Ensure physical sealing of all the meters installed at the trading points • Market Participants should ensure that every check meter operates from VT windings different from those of the main meters • Double metering issues at some GenCo locations need to be addressed. • Complete installation of Disco Boundary meters. • Address observed discrepancies between the incomer energy and the sum of the energies on the associated feeders at some locations. • NERC should consider requiring the MO to submit periodic compliance reports on metering requirements during the lead up to TEM.

Item	Gap for TEM	Action Plan
Metering for Substation Consumption Responsibility: DisCos, NERC, TCN	• A good number of Substation consumption meters are not working or nonexistent; meters are typically not read or tracked.	• NERC should request the Discos to identify the substation meters within their license areas, read such meters monthly along with the revenue meters and produce bills based on the meter readings for payment by the TSP. • The MO should draw up a programme to go round the country to activate all the substation consumption meters.
Meter Security and Data Access Responsibility: MO	• Inadequate physical security for grid meters.	• MO should introduce strong preventive controls that enable security of the meter, its calibration and operation, and the meter data records.

Item	Gap for TEM	Action Plan
Compliance with Market Rules for Meter Data Collection and Management Responsibility: MO	• Meter reading is done by the Market Participant and the System Operator monthly, but not jointly as recommended in the Market Procedure; no reading minutes are prepared. • The AMR data collection system for remote access to the information stored in the meters is yet to be fully implemented. • SO has no way to independently verify GenCo reported hourly meter readings.	• Market Operator should ensure compliance with the process of data collection and management as specified in Market Rules. • MO should insist on reading minutes in respect of the monthly meter readings. • The MO should conclude the development of the AMR data collection system for remote access to the information stored in the meters. • O&M of the metering and AMR system should be outsourced to a private company with the required expertise • Staff training is required on Market Rules, Market Procedure, the Grid Code and the Operational Procedure. • The necessary adjustments for technical losses due to the installation of trading point meters at locations other than those prescribed have not been addressed to date. This should be outsourced to competent contractors to ensure efficiency and fast track implementation.

Item	Gap for TEM	Action Plan
SO Communi-cating, Tracking and Reporting of GenCo/IPP Contract Quantities Responsibility: SO (lead), MO, NBET, GenCos	• GenCo half hourly meter readings are not transmitted to the MO, only monthly energy totals. • Current practices for tracking generator Available Capacity are wholly inadequate. • No arrangements in place to track and transmit to MO other data needed to calculate contract quantities under the PPAs, including: number of startups, time on hot standby, uninstructed generation, fuel availability, environmental temperature.	• A working group consisting of SO/MO, NBET and representatives of GenCos and IPPs should be set up to address the current gaps in tracking and calculating GenCo contract market quantities. • SO/MO should establish a scheduler's desk at NCC that will operate during the day shift. The scheduler is responsible for ensuring compliance with Market Rules and contracts for recording, collecting, tracking and confirming operational data.

Item	Gap for TEM	Action Plan
SO Communi-cating, Tracking and Reporting DisCo Contract Quantities Responsibility: SO (lead), MO, NBET, DisCos NERC	• Due to inadequate system control by SO, grid dynamic exigencies and grid indiscipline by DisCo at times, DisCo's actual energy consumption differs from the Vesting Contract share allocations, in too many cases by a wide margin. • Lack of communication from SO to DisCos on available grid generation and load allocation. • Data exchange interfaces between SO and Market Participant is largely in the form of voice messages and control room logbook entries. There is actually no forum for comparison of operational notes. • Some SO staff interacted with are not conversant with either the Grid Code or the Market Rules.	• There should be regular, monthly interface/ coordination meetings between TCN (TSP/SO) Regions and the DisCos within their areas of jurisdiction to deliberate technical issues regarding DisCo load allocation. • SO needs to improve communications with DisCos to provide the following information regularly: quantum of power on the grid and DisCo's share thereof, in accordance with the Vesting Contract; and NCC's daily operations report. • Need to encourage the culture of constant communication of events between stakeholders. Such communications should be entered into Control Room logbooks and thereafter entered into computer data bases. • SO/MO, with input from NBET, should develop a detailed operating procedure for scheduling, operating, tracking and communicating DisCo contract quantities. • NERC should consider requiring an independent evaluation of SO performance in load allocation and related communications with Market Participants. • NERC should require the SO to submit regular compliance reports showing the status of targeted improvements, as per independent evaluation. • Field staff should receive training on the requirements of the Grid Code and the Market Rules.

Item	Gap for TEM	Action Plan
MO Telecom-munications and IT Infrastructure for Meter Data Collection and Management Responsibility: MO	• Insufficient internal control processes to protect the meter data records and other critical data from data repudiation, malicious use from unauthorized users, data loss, abuse etc. • Server and data infrastructure hosted by various departments are distributed and located in each separate department location which increases the probability and risk of data loss, abuse of data, malicious use from unauthorized users, data repudiation etc. • Access to data and system resources are generally un-auditable and unsecured • Access to critical areas such as server room, AMR room and Treasury where confidential and critical data are stored is not securely restricted and auditable. • The existing email system is currently outsourced and thus will be difficult to implement e-discovery processes as required by the Market Rules Section 47.1.3. • No evidence of an Electronic Document Management System (EDMS) or other alternative to enable document archival compliance • AMR system is not fully functional at present, and some of the grid meters are yet to be equipped with AMR. • No redundancy or resilience at the AMR Hub. AMR workstation is vulnerable and highly insecure.	• Create new ICT corporate governing structure, ICT policy and standards document to cover ICT operations across the enterprise network. • Establish required levels of internal control to secure all data obtained and processed by the MO. • Centralize server resources across the various departments. Access to these resources should be authenticated against an enterprise directory service. • Ensure compliance with the Market Rules on data collection, processing and storage. • Server room should be relocated to a special fit-for-purpose room in a restricted part of the building with security arrangements. • Fully implement AMR as the primary system for collecting grid meter data and feeding the data to the settlement system. • Install at least one redundant AMR (hub – ACTARIS System) to address risk of unplanned AMR hub outage. • Create a private built-for-purpose web portal for: all energy data from the System Operator; and all energy data supplied to Market Participants. • Access to the proposed secure web portal for submitting and accessing confidential information shall be integrated with a multifactor authentication server platform. • Create a highly detailed Business Continuity plan and a remote Business Continuity Center (BCC). • Hosted e-discovery services should be procured as part of the hosted email service contract. This ensures that all incoming and outgoing emails are archived and available for retrieval in the event of the discovery process in civil litigation matters.

Item	Gap for TEM	Action Plan
MO/SO Determination of Available Capacity for GenCo Capacity Charges Responsibility: SO (lead), MO, NBET, GenCos, IPPs	• Nonexistent or inadequate systems in place by SO to record, track, and confirm with the Market Participant and transmit to the MO how much of the hourly operational data required to calculate GenCo/IPP Available Capacity. • The current practice used by the MO of using the daily peak generation as the plant Available Capacity is erroneous and no longer tenable. • Under the PPAs, the GenCos are supposed to notify NBET and SO of fuel supply limitations. At present, there is no formal procedure for the GenCo/IPP to report fuel availability to the SO. • No written confirmation from NCC of operating instructions to Market Participants, only verbal; neither is reception confirmed in writing by the receiving end. • No daily reconciliation of or agreement on contract quantities between SO and Market Participants.	• A working group consisting of SO, MO, NBET and representatives of GenCos and IPPs should be set up to address the current gaps in tracking and calculating Available Capacity for GenCo capacity charges. • MO/SO requires training on data requirements for determining Available Capacity, the steps in the calculation and the associated market and operating procedures. • SO must implement new processes and systems to record, confirm and report the hourly operational data that is needed to calculate Available Capacity, in coordination with NBET. • A procedure should be put in place for the SO and GenCo to report on a daily basis the fuel availability to the power plant, and for the SO to record and report the information to the MO/NBET. • A procedure should be put in place for the SO/MO to confirm the fuel availability information reported by the generator. • MO/NBET should develop a model to input the hourly operating data provided by the SO and calculate the monthly billing determinants for capacity charges. MO/SO will require training on the use of the model. • SO/MO should establish a scheduler's desk at NCC for collecting and reporting the operational data used for settlement of capacity and energy charges. • Implement the Instructions Recording Procedure, as developed by NIAF experts. • MO/SO should consider developing manual on installed capacity requirements that clarifies the determination of Available Capacity, including GenCo operating and reporting requirements and capacity testing.

Item	Gap for TEM	Action Plan
SO Compliance with Grid Code Requirements for Load Allocation to DisCos Responsibility: SO (lead), DisCos, NBET	• The actual deliveries to DisCos do not meet the load allocation in accordance with share percentages in Vesting Contracts for various technical reasons and inadequate SO process controls. • The DisCo load centres regularly violate their allocations. • There is also preponderance of grid indiscipline both on the part of SO and DisCo. • The load allocation schedule as sent out by NCC to the Area Control Centres currently does not get to the Disco. • Violations of load allocations are not sanctioned.	• TSP should develop a detailed grid network study to establish the level of voltage support requirement of the grid to support DisCo load allocations as shown in Vesting Contracts. • TCN should thereafter put plans in place to procure and install such required facilities. • SO/NCC should document all variations between actual allocations and Vesting Contract figures regularly and circulate to all stakeholders stating clearly the reasons for the variations. • TCN/SO/NCC to demand reception of allocation schedule from Regional Control Centres (RCC's); RCC's should demand reception of allocation from 132kV substations and 132kV substations to demand reception of allocation from Disco load centers. These documentations should be circulated to all relevant stakeholders. • SO/NCC should send the daily allocation to all Discos; demand evidence of reception and document. Allocations should also be published on the SO's website. • SO should track and record instructed vis-à-vis uninstructed load drawn by DisCos. SO should promulgate new operating procedures for such tracking and recording. • All load allocation violations shall be documented by the SO and all relevant stakeholders duly informed. Sanctions should be in accordance with laid down procedures in the Grid Code and Market Rules.

Item	Gap for TEM	Action Plan
SO Compliance with Grid Code Requirements for SCADA, Measurement and Data Exchange Responsibility: SO	• Consortium of Siemens and Telemit is yet to complete the restoration of the SCADA system. We are informed that work is in progress. • RTU's and Communication Facilities are thought to be deteriorated along with the generally deteriorated state of the Control Centre. • NIPP substations and generating stations are not yet integrated into the SCADA base. • Need for TCN should to put more effort into the maintenance of the existing infrastructure. • Gap in the staff skills as far as SCADA is concerned; need SCADA engineer on the Operators shift. • Training of Operations and Maintenance Teams on SCADA/EMS greatly needed.	• A fully functional SCADA EMS is highly desirable for TEM but not a necessary condition. • All NIPP substations and generating stations should be integrated into the SCADA base. The same goes for all new 330kV and 132kV transmission stations. • Close gap in the skill level of the System Operators as far as utilization of existing SCADA is concerned. It would be desirable to have a core SCADA engineer on the Operators' shift. • Provide training of Operations and Maintenance teams on SCADA. • Meanwhile a two-year Maintenance Contract with a private contractor should be in place until TCN staff are ready for the handover.

Item	Gap for TEM	Action Plan
Submission of Scheduling and Despatch Data and Contract Nominations Responsibility: SO (lead), MO, NBET, GenCos, IPPs	• Non-adherence to rules and procedures for submission of data from GenCo to SO. • Lack of SO process controls. • Non-adherence to best practices for confirmation of delivered quantities. • Lack of automation and computerization. • Lack of training.	• Form working group consisting of SO, MO, NBET and representatives of GenCos and IPPs to address data submission systems and processes. • Develop formats, data entry templates and associated instructions manual for the Daily Nominations to be submitted by generators. • Formalize the procedures to be used by generators for submission of Daily Nominations, with reference to draft procedures developed by NIAF consultants. • If advisable, provide a website portal accessible to the generators where they can enter their Nominations directly into a database that is then used by the SO and MO. • Formalize the procedure for SO confirmation of receipt of Nomination to the Generator. • Conduct training on the requirements in the Market Rules for submission of scheduling and despatch data and contract nominations.
GenCo Provision of Ancillary Services Responsibility: SO (lead), GenCos	• At present, only a few of the power plants provide spinning reserves and black start. Other power plants have to be encouraged to join in the provision of such services too. • Most of the time the system runs without any spinning reserve at all. • Schedules attached to Ancillary Services Agreement between TCN and GenCos are not complete. Efforts should be made to complete them.	• Claims by individual plant, especially as far as voltage support and black start is concerned, should be verified by the SO/TCN before Connection Agreement can come into operation. • Operations planning should henceforth include computation of daily ancillary services requirement. Furthermore, until SCADA is fully available, efficient documentation processes should be put in place to accurately report instructed deployment of ancillary services. • Some loads connected to both the 132kV and 33kV networks introduce harmonic issues. SO/NCC should have a record of all such load plants and track the load characteristics. Thorough study of such loads should be immediately commissioned to determine compliance to provisions of the Grid Code.

Item	Gap for TEM	Action Plan
MO/SO Compliance with Market Rules for Contract Register Responsibility: MO, NBET	• At present, the MO/SO does not have a Contract Register. • The MO has access to the PPAs between PHCN and IPPs, but does not have access to the PPAs and Vesting Contracts between NBET and the Successor Companies • The MO has not attempted to harmonize the current logic for calculation of settlement quantities for the GenCos with the formulae for calculating the contracted energy and Available Capacity as specified in the PPAs. • The SO/MO may not be cognizant of operating requirements contained in the PPAs.	• NBET should prepare the Contract Register in a form that provides clear instruction to MO regarding calculation of settlement quantities. The Contract Register should also provide clear instruction to the SO to the extent that the SO must take into account the terms of the contracts during system operations. • MO and NBET should establish a working group to harmonize the logic used by the MO to calculate settlement quantities with the formulae in the contracts.
MO Settlement Statements Responsibility: MO	• Notwithstanding the aforementioned erroneous calculation and non-tracking of some contract quantities used in PPAs and Vesting Contracts, the monthly process used by MO for determination of settlement quantities is largely compliant with TEM rules and procedures. • The framework for the adjustment of the readings for the possible losses due the installation of the commercial meters at locations different from the connection points or the exact boundary points, needs to be developed, to enable the MO apply the adjustments in the calculation of the Settlement Quantities. • MO is not adequately prepared to handle a possible onslaught of complaints and disputes when TEM is initiated.	• MO or consultant to develop required loss adjustment factors in case of meter installation at locations remote from TPs. • The MO should expedite the process of transitioning to the use of the new Settlement Software, and provide adequate training to staff on the use of the software. • Complaints process needs to be aligned with the Market Rules. • The process of resolving complaints by the MO needs to be aligned with rules and procedures. • NERC needs to operationalize its procedures related to market disputes. • MO and NBET need to coordinate regarding respective roles in dispute resolution.

Item	Gap for TEM	Action Plan
MO Settlement System Architecture, including Inter-operability and Security Responsibility: MO	• Use of non-commercial database application as backend for settlement software (less scalable and secure). • Market Operator settlement software architecture lacks sufficient levels of resilience (single-tier architecture -single point of failure). • Insufficient user application access audit and controls • Hosting and posting confidential market data on the public internet on the ONEM web portal. • No evidence of perimeter and choke network firewalls required to prevent unauthorized access to settlement system software. • Access to the settlement software is via wireless connectivity in the site. This introduces new vulnerabilities. Lack of strong user controls to prevent hacking attacks. • Customer Relationship Management (CRM) interface in the software application is inadequate. • Reporting modules are inflexible. • Underdeveloped and inadequate MO ONEM Web portal.	• Backend database application of the Market Operator settlement software application should be upgraded to a leading Commercial Relational Database Management System (RDBMS) application. • Market Operator settlement software should be configured as a two-tier application platform to reduce the risk of single point of failure. • Implement a Lightweight Directory Access Protocol (LDAP) authentication interface to the proposed Enterprise Directory service to ensure that Market Operator no longer relies on application-level security controls to restrict access to the application and data. • Implement application-level cluster to enable High Availability and Graceful Degradation in the event that components of the system fails or become unavailable. • Implement a direct data interchange between the AMR server and the Market Operator Settlement software. • Conduct further review, testing and independent audit of the AMR meter report data. • Conduct functionality and stress testing of the MO's settlement software application (including all modules and features) by an independent software testing lab or entity prior to use. • Energy data reporting from the System Operator shall be distributed to stakeholders by hosting on a private built-for-purpose web portal owned and operated by the System Operator. • All Market Operator related data reporting and communication shall be distributed to stakeholders by hosting on a private built-for-purpose web portal owned and operated by the Market Operator.

Item	Gap for TEM	Action Plan
MO Settlement System Architecture, including Inter-operability and Security **(continued)** Responsibility: MO		• Data partitioning by respective data owners is critical for data management, ownership, auditing, accountability and regulatory compliance purposes • Web portals shall be located on a private (not public) network and only pre-authorized users and stakeholders shall have access to the web portal. • Access to secure web portals shall be integrated with a multifactor authentication server platform. • MO settlement software application should be web-enabled to increase availability, functionality, security, performance and flexibility. • MO should initiate procedures for internal control processes required to secure critical data. • Centralize server resources across the various departments and provide for authenticated access. • Relocate server room to a special fit-for-purpose room in a restricted part of the building. Use of biometric-access control devices complemented by the use of Video Surveillance camera and recording equipment shall constitute the minimum level of site and server room protection. • Create ICT policy and standards document to cover ICT operations across the enterprise network. • Organize training workshops participants and stakeholder that will be accessing the extranet, internet web portal for effective usage and increased stakeholder adoption of the web portals. • Introduction of perimeter and choke firewalls to restrict access to unauthorized users

Item	Gap for TEM	Action Plan
MO Payments Arrangements with DisCos Responsibility: MO	• The systems, procedures and payment timeline used by the MO to receive payments from DisCos are already largely compliant with the Market Rules for TEM. • Due to current problem of DisCo collections, the market invoices issued by the MO are not binding on the DisCos; instead there is cash flow waterfall. This will need to change under TEM. • Inadequate tracking of and no billing for prior nonpayment by DisCos. • MO website portal for complaints is not yet operational. • None of the DisCos have posted the required Security Covers to MO and NBET for their liabilities arising from the Market Settlement process.	• DisCos should be required to provide adequate security cover that the MO can draw upon in the event of DisCo nonpayment. • NERC should order the DisCos to post their security cover as soon as practical during the Interim Period prior to TEM. • The MO should form a working group with representatives of DisCos and NBET to harmonize new banking arrangements for TEM and develop appropriate arrangements to replace or revise the current system of joint escrow accounts and standing orders used by MO and DisCos. • MO should monitor and participate to the extent possible in NBET's procurement process for a payment agent, so as to glean lessons learned that may be applicable to the MO. • MO/NBET need to institute suitable methodology and arrangements for accounting and billing the DisCos for payment arrears, and paying the service providers for past due amounts. • MO should create a customer interface on the MO website to facilitate administrative matters such as filing of complaints regarding Settlement Statements. • MO manual on Procedures for Admission and Participation during the Transitional Market can be enhanced by presenting full description of the calculation of the charges for each service, including calculation and administration of interest and penalties, if any, on late and nonpayment. • NERC should lead development of backstop solutions in case DisCo nonpayment persists during TEM, in consultation with Market Participants and FGN.

Item	Gap for TEM	Action Plan
MO Accounts Responsibility: MO	• Due to MO privacy reasons, we are unable to verify that separate ledgers were created and maintained for the accounts specified in Market Rules.	• Provide for randomly scheduled third-party independent audit of the MO operated accounts to provide greater transparency and reduce the financial risk of the Electricity Market.
MO Accounting Systems for Billing and Payments Responsibility: MO	• The present system of accounting for market transactions relies on the use of Excel spreadsheets to record the monthly payments waterfall process. We suspect spreadsheet accounting will prove untenable for TEM. • MO does not have the capacity to monitor on an ongoing basis the bank transactions that occur in its joint escrow accounts with the DisCos. • Since, at present, there is no expectation that nonpayments accrued to date will ever be recovered, the MO does not bother with detailed tracking of payments and nonpayments using standard accounting practices. • The MO's settlement system fails to integrate with either the MO's own finance accounting system or a payment agent's system.	• MO will need to start maintaining adequate accounting records for amounts past due to the various service providers due to DisCo late- or non-payment during TEM, and provide for the calculation of associated interest and penalties. • MO should work with the banks to develop a real-time integration interface with the bank account reporting portals, so that the MO can effectively track payments received from the DisCo and disbursed to the service providers. In general, MO needs to maintain its own record of every payment and disbursement transaction in the market. • We suspect that the current reliance on the use of spreadsheets by the MO accounting unit is inadequate and unsustainable for TEM. The MO should form a project team to make recommendations on software systems, processes, organization and staffing for tracking and accounting for transactions in the market. The team should also make recommendations on how to best integrate the market transaction tracking and accounting system with the settlement system. • NERC should determine allowable interest rates and penalties associated with late- and non-payment amounts.

Item	Gap for TEM	Action Plan
NBET Processes and Systems for TEM: Settlement Process Responsibility: NBET (lead), MO	• NBET has developed the basic design for its settlement process, but as yet it is untested. • There is a lack of coordination between NBET and MO regarding planning for the settlement process under TEM, including processes, systems and interfaces.	• The arrangements required to implement and automate, as far as possible, the NBET settlement system are being developed and/or in the process of procurement, as informed by NBET. Such arrangements should be tested during the Interim Period. • There is a need for stronger coordination between NBET and the MO during the lead up to TEM on settlement processes, software, interfaces, roles and responsibilities that each entity will manage. • A working group approach with regular schedule of meetings between the two parties, e.g. biweekly, may facilitate joint project planning and adherence to the schedule for TEM.
NBET Processes and Systems for TEM: Invoicing Responsibility: NBET (lead), GenCos	• NBET processes and system for invoicing are untested. • Successor Company GenCos have not yet adopted the practice of submitting monthly invoices that can be vetted by NBET. • Submission of market invoices to DisCos is currently handled by the MO, and NBET is not involved.	• The Successor Company GenCos should adopt the practice of submitting monthly invoices to MO/NBET. • MO, NBET and NERC need to work out the framework for allocating roles and responsibilities. • MO and NBET should work together to design and implement critical interfaces for data exchange related to market invoices. • MO/SO and NBET should work together to develop the framework for NBET to monitor contract quantities despatched by SO and ensure that operations are consistent with terms and conditions of the PPAs.

Item	Gap for TEM	Action Plan
NBET Processes and Systems for TEM: Payments Arrangements Responsibility: NBET (lead), MO, NERC	• NBET has not yet instituted required banking arrangements to handle market transactions, as the Market Operator is still handling payment processing to all services providers. • An RFP process to procure an authorized payment agent to directly handle and oversee receipts from DisCos and payments to GenCos and DisCos is currently underway. • Lack of clarity on the need for or mechanism for a payments waterfall in the event of DisCo nonpayment during TEM.	• MO, NBET and NERC should make a joint proposal on the transitioning of payments responsibilities and functions from MO to NBET. The working group should also come up with a proposal for how to integrate MO and NBET systems for these functions. • NERC should take the lead to develop suitable arrangements in lieu of a payments waterfall that will provide adequate financial security for NBET and MO in the event of DisCo nonpayment during TEM.
NBET Processes and Systems for TEM: IT and Telecommunications for Settlement System Responsibility: NBET	• NBET IT and telecommunications are still under development and not yet adequate for TEM.	• Create ICT corporate governing structure. • Create private built-for-purpose web portal owned and operated by the NBET for business communications and reporting. • The proposed web portal shall be located on a private network (not hosted on the public network). • Access to the proposed secure web portal for submitting and accessing confidential information shall be integrated with a multifactor authentication server platform. • Create highly detailed Business Continuity plan to cover all critical data and telecommunicating processing components. • Complete the acquisition and installation of an Enterprise Resource Program (ERP) application that will manage the NBET payment and invoice process (including other NBET functions). • Include relevant stakeholders such as NERC or qualified representatives of Market Participants in the development of the NBET Business Analysis and Technical Implementation design plan. This will ensure final implementation meets all the required compliance objectives of the regulatory entity.

Item	Gap for TEM	Action Plan
NBET Accounting for Billing and Payments Responsibility: NBET	• NBET systems and process for accounting for market transactions are still under development. • Still deciding whether accounting functions for market transactions will be done in house or outsourced.	• NBET or its designated agent needs to develop and implement an accounting system to record and manage market transactions drawing on best utility practices used by market operators. • The system should integrate with NBET's invoicing system and with bank transaction accounting records.
NBET PPAs Responsibility: NBET (lead), GenCos	• Although NBET has executed the PPAs with the GenCos, the contracts are not yet effective.	• It is expected that NBET will populate all the schedules under the PPA before the commencement of TEM.
Novation of PHCN PPAs to NBET Responsibility: NBET (lead), PHCN	• None of the existing PPAs with AES, AGIP or Shell has been novated to NBET.	• NBET to complete discussions with PHCN on the novation of the existing PPAs with AES, AGIP or Shell. • NBET has also begun independent discussions with AES and Shell on this subject. Negotiations for the novations is progressing well and NBET is confident of concluding all the novations before the winding-up of PHCN or the commencement of TEM, whichever is earlier.
NBET-DisCo Vesting Contract Responsibility: NBET (lead), DisCos	• Although NBET has executed the Vesting Contracts with the DisCos, the contracts are not yet effective.	• NBET still expects the DisCos to put in place the required security cover before the Vesting Contracts can become effective. • It is also expected that NBET will populate all the schedules under the Vesting Contracts before the commencement of TEM.

Item	Gap for TEM	Action Plan
Grid Connection Agreement between TCN & DisCo/GenCo Responsibility: TSP (lead), DisCos, GenCos	• Grid Connection Agreements have been signed, albeit in a generic form. • For the GenCos, some schedules have not been completed. • Schedule attachments are missing from the Disco connection agreements.	• All operating parameters should be duly filled out in the schedules before the Agreements can come into effect. • Where there are no documentations, plant operators should liaise with the SO for studies and tests to determine the actual capabilities of the plant to provide such services. • Schedules attached to the DisCo Connection have to be filled out before Agreements can be operational and TEM declared. • TCN is not comfortable with the interface boundary with the Disco's; neither are the Discos. The general consensus is that the boundary should be after the 33kV bus bars, at the interface metering points. These boundaries should therefore be adjusted, going into TEM.
Ancillary Services Agreement between TCN and GenCo Responsibility: TCN (lead), GenCos	• Only three plants have proven capabilities to offer frequency support while only one offers black start. • Defective schedules should be amended. • No unit offers more voltage support than its capability during normal operations. • Ancillary services are not scheduled by Operations Planning group. • Adequate metering of reactive power and monitoring of ancillary services deployment.	• There is a need to reassess the realistic capabilities of units to deliver ancillary services. However, this should not stop TEM from being declared. • Available characteristics of units should be duly completed in the schedules. • SCADA, proper metering and adequate voice and data communication facilities should be put in place. • Ancillary services scheduling should be performed by Operations Planning, just like generation scheduling.

Item	Gap for TEM	Action Plan
Compliance with CPs for Initiation of TEM, as Shown in Market Rules Responsibility: MO, SO, NBET, NERC	CPs in the market rules pertaining to the following roles and responsibilities are not fully met at present: • Systems and procedures to be used by MO, SO and NBET to meet the requirements in Market Rules and Grid Code • NBET execution of the Vesting Contracts, PPAs and the novation of PHCN legacy PPAs • Set up of Dispute Resolution Panel	• Complete the development, implementation and testing by the System Operator, of the systems and procedures required to implement the Grid Code. • Complete the development, implementation and testing by the Market Operator, of the systems and procedures to implement the Market Rules for the Transitional Stage. • NBET needs to execute the Vesting Contracts, PPAs and complete the novation of PHCN legacy PPAs. • Constitute the initial Dispute Resolution Panel and test systems and procedures.
Shadow Trading during the Lead up to Declaration of TEM Responsibility: MO, SO, NBET, NERC	• New processes, systems, software, roles and responsibilities for TEM need to be thoroughly tested during the lead up to TEM.	• A working group consisting of MO, SO, NBET, NERC and qualified consultants should be set up to plan and oversee Shadow Trading during the Interim Period. • There should be a role for Market Participants to provide constructive feedback. • The initial task of the working group is to monitor the settlements and payments process for the month of October 2013, for which the payment cycle should be concluded by end of November 2013.

2 COMPLIANCE WITH METERING REQUIREMENTS AT TRADING NODES

One of the Conditions Precedent for the initiation and implementation of the transitional stage of the Nigerian electricity market is the identification and adequate metering of all the Trading Points in the Electricity Market. The Trading Points are the points at which the generators inject power into the grid and the points at which the distributors and other large power consumers extract power from the grid. These points are located at the Generator/Transmission (G/T) interfaces for the generators, and the Transmission/Distribution (T/D) interfaces for the distributors.

The Table 2.1 shows the number of trading points and the number of meters installed at the various trading points for the different categories of Market Participants, as at 30th September 2013, according to the Market Operator's records and sample field investigations.

Table 2.1: Numbers of Trading Points and Grid Meters

Type of Participant	No. of TPs	No. of Meters
GenCos	81	95
Discos	675	675
Inter-disco	40	36
Large consumers	9	9
International Utilities	5	5
Total	810	820

The secondary output of the T/D interface transformers (incomers) is also metered, for among others, the purpose of energy reconciliations across the trading points. There are 288 of such incomers which have all been metered.

Therefore, the total number of trading points in the Nigerian Electricity Market is 810 as at September 30, 2013, out of which 806 have been metered. Total number of interface meters in the network, including the incomer meters is 1,098

Another type of metering system which the MO is implementing is the Transmission substation metering, which are designed to measure the consumptions at the substations and reduce the TLF values passed over to the Discos.

2.1 Metering for GenCos

2.1.1 TEM Requirements

The following grid metering infrastructure for generators will be required for TEM:

- As far as possible, the metering system for the generators shall be located at the actual connection point, which is at the high voltage side of the step up generator transformers
- There should be Main and Check meters installed at the same location for the measurement of energy sent out by the generators. In principle, Main and Check meters measurements shall be coincident.
- Meters shall be static type and shall be capable of measuring data at least half-hourly, and record them automatically in Data Registers
- Data Registers shall have adequate capacity to store for at least three (3) months

- The accuracy of the Meters should conform to the relevant IEC Standards, e.g. meter accuracy shall be 0.2
- Meters should be programmable and should be able to stack readings for at least 9 months
- To prevent unauthorized access to the data in the meters, a security scheme shall be incorporated for both local and remote access to the meter brains
- The meters shall be installed in a manner such as to provide protection from moisture and dust ingress and from physical damage, including vibration. In addition, the meter must be physically sealed to prevent unauthorized access
- Main and Check meters shall operate from separate Instrument Transformer (CTs and VTs) windings
- Different generators should be differently metered, and there should not be the possibility of double metering for any of the generators
- The meters should be AMR compliant to facilitate remote reading. That is, they shall have adequate communication facility to permit automatic downloading

2.1.2 Status of the Generator Metering (As – is State)

The Nexant team determined the status of the Generator Trading Point (TP) meters through field investigations, discussions with the Generator representatives and review of the Market Operator's report. Table 2.2 shows the number of Trading Point Meters associated with the generators, including the NIPPs and the IPPs.

Table 2.2: GenCo Trading Point Meter Statistics

Generator	No. of TP Meters
AES (IPP)	2
Afam IV & V	3
Afam VI (Shell IPP)	4
Alaoji (NIPP)	-
Delta	12 (10 are TP meters)
Egbin	8
Geregu	3
Geregu (NIPP)	3
Ibom Power (IPP)	4
Ihovbor (NIPP)	-
Jebba	2
Kainji	3
Okapi (Agip IPP)	8
Olorunsogo	6 (2 are TP meters, 4 are gen unit meters)
Olorunsogo (NIPP)	6 (2 are TP meters, 4 are gen unit meters)
Omotosho	6 (2 are TP meters, 4 are gen unit meters)
Omotosho (NIPP)	3
Rivers (IPP)	-
Sapele	6
Sapele (NIPP)	6
Shiroro	10
Total	95, but 81 only are TP meters

Samples of interfaces were selected among the generators for Trading Point meter investigations. The generators selected and visited are as shown in the Table __.

Table 2.3: Sample of Generator Trading Point Meter Investigations

Generator	Associated interfaces	Date of visit	No. meters Incomers	No. meters Feeders
Egbin	Egbin power station	18/09/13	NA	8
Olorunsogo1	Olorunsogo 1 power station	19/09/13	NA	6 (2 are TPs)
Afam IV – V	Afam power station	21/09/13	NA	3
Afam VI (Shell IPP)	Afam power station	21/09/13	NA	4
Shiroro	Shiroro power station	03/10/13	NA	10
Delta	Delta Power Station	18/10/13	NA	12 (10 TPs)
Totals				43 (37 TP)

The above table shows that out of the 21 generators, made up of the successor generating companies, the NIPP Plants and the IPPs currently generating into the grid, six were visited. Also, 43 out of the 95 metering Points (i.e. 45%) were investigated. Tables showing the status of the meters at the G/T interfaces visited, with comments on some of the observations specific to the generators, are attached as appendices.

The following general comments are made regarding all the Generator Trading Point meters investigated, and by extension, all the generator Trading Point meters in the network:

- The metering systems for the generators are located at the high voltage side of the step up generator transformers, but not exactly at the connection points. In practice, metering CTs are not available in most bushings of the unit transformers, which are the exact connection points. Where they are available, their use is discouraged for security reasons. Also, in most power stations, the spaces immediately after the unit transformers are put to one use or the other, such that no free standing CTs can be installed beside the unit transformers for the metering system. Therefore, except for very few cases, like Delta power station, Afam VI, Okpai and AES IPPs, where the metering systems are installed at the exact connection points, the metering system for most of the generator trading points are located at the outgoing lines from the generators to the transmission grid

- There are no check meters installed to reconfirm the measurements of the energy sent out (by the generators) through the Main meters, except at the Afam VI, Okpai and Ibom Power IPPs.

- The Meters for all the generators, apart from Olorunsogo (which are Actaris SL7000) are EDMI meters. These are static meters which are capable of measuring data half-hourly, and record them automatically in Data Registers

- The meters are programmable, but the Data Registers do not have adequate capacity to store data. They do not store the previous readings at all. They only store the energy consumed during the month for a period of one month. By the end of the month, the data is deleted to make room for another month's energy consumption data

- The accuracy class of the Meters is 0.2, which conforms to the relevant IEC Standards

- To prevent unauthorized access, to the data in the meters, a security scheme is incorporated for both local and remote access to the meter brains. That is, the meters are electronically sealed by means of security software.
- The meters are installed in a manner such as to provide protection from moisture and dust ingress and from physical damage, including vibration. However, the meters are not physically sealed.
- Where the check meters are installed, the Main and Check meters operate from separate Current Transformer (CT) windings, but from the same Voltage Transformer (VT) windings.
- The meters are all AMR compliant to facilitate remote reading. That is, they have adequate communication facility to permit automatic downloading

The following issues that need to be addressed at specific locations were noted during field investigations:

- Double metering is observed for Afam VI and AES IPPs. The energy sent out by Afam VI generator, which is measured at the connection point for the generator, is also measured by the meters at the out-going lines to the grid, which are the Trading Point meters for Afam IV & V generators. The same applies between AES IPP and Egbin Generator. There are two 330/132KV inter-bus transformers at Egbin, whose outputs are metered on the two outgoing 132KV lines to Ikorodu. The AES generation is sent out at 132KV and metered at the high voltage side of the step up generator transformers. This AES generation is sent to the grid through the same outgoing 132KV lines to Ikorodu. Double metering is suspected here in favour of Egbin.
- The Trading Points for Rivers IPP, Alaoji and Ihovbor NIPPs are yet to be metered
- The relay room, where the meters are situated at Olorunsogo power station is very hot due to faulty air-conditioning system. This excessively high temperature is capable of affecting the performance and accuracy of the meters.
- GT15 and GT16 meters at the Delta power station are suspected to have been wired together. They measure and read synchronously.
- The CVT on the 132KV Busbar at the Delta Power Station is out of order. This affects the metering of the Station Service Transformers SST1 and SST2.
- The 132/3.3KV, 5/6.7 MVA SST1 &SST2 in Delta Power Station are connected to the 132KV bus, after the energy sent out has been metered. The energy sent out is metered at the high voltage side of the step up transformer, while the 132KV busbar is supplied by the 330/132KV Inter-bus Transformer.

2.1.3 Gaps to be Addressed for the initiation of TEM

The gaps between the TEM requirements and the current status of the Trading Point metering for the generators are listed below:

- Except for very few cases, like Delta power station, Afam VI, Okpai and AES IPPs, where the metering systems are installed at the exact connection points, the metering system for most of the generator trading points are located at the outgoing lines from the generators to the transmission grid.

- There are no check meters installed to reconfirm the measurements of the energy sent out (by the generators) through the Main meters, in line with the Metering Code, except at the Afam VI, Okpai and Ibom Power IPPs.
- The Data Registers for the EDMI Meters used for the generator trading points do not have adequate capacity to store data. They do not store the previous readings at all.
- The EDMI meters are not physically sealed on site. This leaves room for the possibility of unauthorized access to the meters.
- Where the check meters are installed, the Main and Check meters operate from separate Current Transformer (CT) windings, but with the same Voltage Transformer (VT) windings, against the recommendations of the Metering Code.
- There is double metering for Afam VI and AES IPPs in favour of Afam IV-V and Egbin generators, respectively. That is, the meter for Afam IV-V generation measurement is situated to record the Afam VI generation also. The same goes for Egbin and AES.
- There are no Trading Point meters for the Rivers IPP, Alaoji and Ihovbor NIPPs, which are already generating into the grid.
- The relay room, where the meters are situated at Olorunsogo power station is very hot due to faulty air-conditioning system. Under this condition, the accuracy of the meters is endangered.
- GT15 and GT16 meters at the Delta power station are suspected to have been wired together. They measure and read synchronously.
- The CVT on the 132KV Busbar at the Delta Power Station is out of order. This affects the metering of the Station Service Transformers SST1 and SST2.
- The 132/3.3KV, 5/6.7 MVA SST1 &SST2 in Delta Power Station are connected to the 132KV bus after energy sent out has been metered. This means that energy consumed by the generator for its station services is included in the energy sold to the distributors. The energy sent out is metered at the high voltage side of the step up transformer, while the 132KV busbar is supplied by the 330/132KV Inter-bus Transformer.

2.1.4 Action Plan to Address Gaps

- Like in the cases of Delta power station, Afam VI, Okpai and AES IPPs, the metering system for all generator trading points should be located at the HV side of the step up unit transformer, as close as possible to the transformer bushings, and before the 330KV busbar. As much as possible metering on the outgoing lines to the transmission grid should be avoided. However, where this is not possible and the meters are located on the outgoing lines, the energy sent out should be adjusted for the variations in the meter locations.
- Check meters should be installed at all the trading points by the Generators, to reconfirm the measurements of the energy sent out through the Main meters, as we have in most of the IPPs, in line with the Metering Code.
- The manufactures of the EDMI meters have been notified of the fact that the Data Register of the meters do not have adequate capacity to store data, and therefore cannot store previous meter readings. They have also been requested to effect necessary corrections without delay. There is a plan to conclude this correction and give the meters the capability to store previous readings, before the end of 2013.

- The MO should ensure physical sealing of all the meters installed at the trading points, to prevent unauthorized access to the meters.
- The Generators should ensure that every check meter operates from VT windings different from those of the main meters, as recommended in the MC.
- The double metering of the AES power in favour of Egbin and that of the Afam VI power in favour of Afam IV – V can be corrected as follows.
- The trading point meters for Egbin generation through the inter-bus transformer should be installed close to the low voltage bushing of the inter-bus transformer. This way, Egbin contributions to the 132KV output of the complex would have been captured before the 132KV busbar where the AES power joins in before going out on Ikorodu Lines 1 & 2. This can be achieved by the Egbin generator before end of March 2014.
- The trading point meters for Afam IV generation should be installed close to the low voltage bushings of the unit transformers, before the 330KV busbar. The meters for Afam V generation are installed according to the MC requirements. Then after, the meters on Alaoji lines 1 &2 should be decommissioned. The generator should arrange for this before the end of March 2014.
- The MO should be requested to install Trading Point meters for the Rivers IPP, Alaoji and Ihovbor NIPPs, which are already generating into the grid.
- The faulty air-conditioning system in the Relay room where the trading point meters are located at Olorunsogo Power Station should be repaired by the GenCo CEO currently operating the station, so that the accuracy of the meters is not impaired by the excessive heat in the room. This can be achieved before the end of November 2013
- GT15 and GT16 meters at the Delta power station should be investigated by the MO to correct the suspected wiring error.
- The faulty CVT on the 132KV Busbar at the Delta Power Station, which affects the metering of the Station Service Transformers SST1 and SST2 should be repaired by the generator. This can be achieved before end of March 2014.
- The connection of the 132/3.3KV, 5/6.7 MVA SST1 &SST2 transformers in Delta Power Station should be amended by the generator, so that energy consumed by the generator for its station services is not included in the energy sold to the distributors.
- The MO is the responsible party for ensuring compliance with the Metering Code. NERC should consider requiring the MO to submit periodic compliance reports showing the status of punch list items, including actions required by MO as well as Market Participants, problems encountered, corrective actions to be taken, and the schedule for remaining work to be done.

2.2 Metering for Discos

2.2.1 TEM Requirements

The requirements on the Disco Trading Point Metering System for the initiation and implementation of TEM are as follows:

- The Metering Code provides that the Main and Check Metering Systems shall be located at the LV side of the Power Transformer of the substation that connects the Transmission System with the Distribution System. However, there are situations or cases where different feeders from the LV side of the same Power Transformer supply different Discos.

In order to eliminate ambiguity and possibility of disputes associated with quantity of power consumed by the different Discos, the feeders have been accepted as the Trading Points. Meters located at the Incomers of the Power Transformers are for use for energy reconciliation and verification. Due to losses on the conductors between the incomer and feeder meters, the energy measurement of the incomer meter shall be higher than the sum of the energy measurements of the feeder meters, within an acceptable limit of 2%. Again, the Main and Check meter measurements shall be significantly coincident.

- Meters shall be of static type and shall be capable of measuring data at least half-hourly, and record them automatically in Data Registers.
- Meters shall be programmable and Data Registers shall have adequate capacity to store for at least three (9) months.
- The accuracy of the Meters should conform to the relevant IEC Standards, e.g.meter accuracy shall be 0.2 or 0.5.
- Where a User proposes to utilize meters that do not meet the required Standards, a derogation submission must be made to the Market Operator.
- To prevent unauthorized access, to the data in the meters, a security scheme shall be incorporated for both local and remote access to the meter brains.
- The meters shall be installed in a manner such as to provide protection from moisture and dust ingress and from physical damage, including vibration. In addition, the meter must be physically sealed to prevent unauthorized access.
- The metering systems for the different Trading Points shall operate from different instrument transformers (CTs & VTs).
- Main and Check meters shall operate from separate Instrument Transformer (CTs and VTs) windings.
- The meters should be AMR compliant to facilitate remote reading, i.e. they shall have communication facility to permit automatic downloading.
- Besides the Trading Points (TPs) at Substations, there are other TPs associated with the Distributors which must be metered for TEM. These are the inter-Disco TPs. The inter-Disco TPs are the trading points associated with a feeder supplying different distribution networks belonging to different distribution licensees.
- According to the Metering Code, the inter-Disco metering system shall be located at both ends of the line between substations of the affected Discos. This MC requirement may be difficult to achieve in the country because distribution substations (33/0.415KV & 11/0.415KV s/s) are commonly installed along the lines, at both sides of the boundaries of the Discos. Therefore, metering the line at the injection substations (33/11KV s/s) of the different Licensees, at both ends of the line does not result in efficient determination or measurement of the Disco consumptions. This leaves the geographical boundaries of the Discos as the most appropriate Trading Points, and the locations for inter-Disco boundary trading point metering systems.
- Another set of trading points are the TPs for large power consumers, who take power at the transmission and sub-transmission voltages. These Trading Points must also be metered for TEM. The TP metering system shall be located at the exact connection points to the transmission grid.

2.2.2 Status of Disco TP Metering (As–is State)

The Nexant team determined the status of the Disco Trading Point (TP) meters through field investigations, discussions with the Disco representatives and review of the Market Operator's report. Table 2.4 below shows the number of Trading Point Meters associated with the Distribution Companies.

Table 2.4: DisCo Trading Point Meters

DisCo	No. of TP Meters
Abuja EDC	79
Benin EDC	45
Eko EDC	86
Enugu EDC	59
Ibadan EDC	94
Ikeja EDC	75
Jos EDC	41
Kaduna EDC	49
Kano EDC	53
Port-Harcourt EDC	58
Yola EDC	36
Total	675

Samples of interfaces were selected among the Discos for Trading Point meter investigations. The Discos and Interfaces selected and visited are as shown in Table 2.5.

Table 2.5: List of Disco Trading Point Meter Investigations

DisCo	Associated interfaces	Date of visit	No. of meters not complying with MC	No. of meters in compliance with MC
Abuja EDC	Katempe 132/33KV s/s	06/09/13	2	6
	Apo 132/33KV s/s	06/09/13	3	11
	Minna 132/33KV s/s	03/10/13	3	8
Enugu EDC	New Haven 132/33KV s/s	10/09/13	4	9
	Abakaliki 132/33KV s/s	11/09/13	2	6
	Nkalagu 132/33KV s/s	11/09/13	2	2
	Oji River 132/33KV s/s	11/09/13	2	5
Eko EDC	Alagbon 132/33KV s/s	17/09/13	2	7
	Ajah 132/33KV s/s	17/09/13	2	7
	Ijora 132/33KV s/s	20/09/13	4	8
Ikeja EDC	Ikorodu 132/33KV s/s	18/09/13	3	13
	Ogba 132/33KV s/s	20/09/13	4	9
P-H EDC	P-H Main 132/33KV s/s	25/09/13	3	7
	P-H Town 132/33KV s/s	25/09/13	4	9
Kano EDC	Kumboso 132/33KV s/s	09/10/13	4	8
	Dan Agundi 132/33KV s/s	09/10/13	2	7
	Dakata 132/33KV s/s	09/10/13	3	6
Yola EDC	Yola 132/33KV s/s	11/10/13	2	5
Kaduna	Birnin-Kebbi 132/33KV s/s	25/10/13	2	6
	Sokoto 132/33KV s/s	26/10/13	3	6
Benin	Benin 132/33KV s/s	18/10/13	4	9
	Delta1 132/33KV s/s	18/10/13	2	6

Total	62	160

The above table shows that out of the eleven Distribution Companies nine Discos with 22 T/D Interface points were visited. Also, 160 out of the 675 TP metering systems (i.e. about 25%) were investigated. Tables showing the status of the meters at the T/D interfaces visited, with comments on some of the observations specific to the Interface Points, are attached as Appendix 1.

Apart from the specific comments on the TP meters on the individual interfaces, the following comments are made regarding all the Disco Trading Point meters investigated, and by extension, all the Disco Trading Point meters in the network:

- The metering systems for the Disco TPs are located at the outgoing feeders, on the LV side of the 132/33KV or 132/11KV Substations. About 99% of the Disco TPs are currently metered. The remaining 1% is made up of new installations that are yet to be metered. The Substation Incomers are equally metered to serve as references for energy reconciliation and verification.

- There are no check meters installed to reconfirm the measurements of the energy received (by the Discos) through the Main meters.

- The Meters for all the Disco TPs are mainly ITRON meters with some EDMI meters in a few locations. The Incomer meters are wholly EDMI. Both the ITRON and EDMI meters are static meters which are capable of measuring data half-hourly, and record them automatically in Data Registers.

- Both meters are programmable. The EDMI meter Data Registers do not have adequate capacity to store data. They do not store the previous readings at all. They only store the energy consumed during the month for a period of one month. By the end of the month, the data is deleted to make room for another month's energy consumption data. However, the GM in-charge of metering in Market Operations confirmed that the manufacturers of the meter have been contacted on this, and that action is on at the moment to address the issue. The ITRON meter Data Registers have adequate capacity to store data. They have the capacity to store up meter previous readings for a period of 12 months.

- The accuracy class of both Meters is 0.2 for the EDMI and 0.5 for the ITRON, which conforms to the relevant IEC Standards.

- To prevent unauthorized access, to the data in both meters, a security scheme is incorporated for both local and remote access to the meter brains. That is, both meters are electronically sealed by means of software.

- The meters are installed in a manner such as to provide protection from moisture and dust ingress and from physical damage, including vibration. The ITRON meters are physically sealed, while the EDMI are not.

- The meters are all AMR compliant to facilitate remote reading. That is, they have adequate communication facility to permit automatic downloading.

- There are no VTs available on the feeders at most of the 132/33KV substations, for the metering of the trading points. As a result of this critical absence, the Automatic Voltage Selector Switch (AVSS) was developed by the MO to enable the distribution of the incomer VT outputs to the feeder metering systems for the prompt implementation of trading point metering in the country.

The following location-specific issues were identified during the field visits:

- The Disco Trading Points at Elelenwo and Rumuosi 132/33KV substations are yet to be metered. Also the Silver Bird feeder at the P-H Town 132/33KV substation is not metered, while the meter for the UST feeder at the same Substation, is not functioning.

- The trading points at Dutse and Azare 132/33KV substations are not metered due to the fact that the feeder CT outputs pass through Transducers, and therefore cannot be used for the trading point metering system. The metering systems at the incomers are being treated as trading point metering systems at both substations.

- The 33KV Guwada/Kuta feeder from the 15MVA, 132/33KV transformer at the Shiroro TS is not metered.

- The meter on the Ijora Cause Way feeder, at Ijora 132/33KV substation is not working. A wiring error is suspected as the reason. Also, the CBN meter at the Dan' agundi 132/33KV substation is not functioning.

- The Nsukka feeder in Enugu EDC is on 66KV while the rest of the country is either on 33KV or 132KV.

- Wide discrepancies between the incomer energy and the sum of the energies on the associated feeders are observed in a number of stations visited. Typical examples are shown in Table 2.6:

Table 2.6: Observed Wide Discrepancies for Readings at TPs

Substation	Discrepancy
Delta TS	6.96%
Effurun	(9.53%)
Irua TS	(207.38%)
Akure TS	(32.26%)
Amukpe TS	(85.06%)

According to the Metering Code, the sum of the feeder energies can be less than the incomer energy by a maximum of 2% of the incomer energy, due to losses on the installations between the incomer metering CTs and those of the feeders. A major reason for this type of discrepancy is the change of the current transformer ratios by the TSP, for network maintenance or modifications of the installations, without reference to the MO for reprogramming of the meters to be consistent with the new CT ratios. For example, the CTs for the T1B incomer at Yola 132/33KV substation were recently changed from 1200/1A to 600/1A which has doubled the reading of the incomer meter, and caused a major variation with respect to the sum of the energies in the associated feeder meters.

- Benin 330KV Station is a confluence of 330KV lines. At the moment, there are 13 No. 330KV lines entering into Benin Station from different generation sources. More are still expected. This situation accounts for the high voltage profile usually experienced within Benin Complex. The Benin Load is therefore constantly used to dampen the system voltage, making it impossible for the current formula for the vesting contract load allocation to apply to Benin EDC. Inadvertently, Benin takes more load than allocated in the Vesting Contract, and this will continue to be so

- In most cases, the geographical boundaries between distributors are not convenient and suitable for the installation of metering systems. In practice, therefore, the inter-disco boundary metering systems are located at positions other than the geographical boundaries of the discos, as shown in the table attached Appendix 2.

- From the table, it can be seen that out of the 40 inter-Disco TPs, 36 are metered, while 4 are yet to be metered. Of the 36 metered, some of the metering systems are installed at the sources of the feeders. Under this condition, the relevant Discos agree on a sharing ratio for the energy recorded by the meters. Some of the meters are installed in enclosures mounted on H-Pole structures located in convenient villages along the lines. However, there is provision in the Metering Code for loss adjustments where meters are located at positions other than those prescribed.

- The trading points for large power consumers correspond to the point at which the consumers connect to the grid.

2.2.3 Action Plan to Address Gaps

The following actions have been recommended to enable the gaps in the Disco Trading Point Metering to be addressed before the initiation of TEM

- The TSP should promptly inform the MO and the affected Distributor, of any installation plan that will require metering or affect the existing metering system. This way, the Trading Point Metering System will always be part of the installations to be commissioned by the TSP. Also, any changes in the existing metering system will be captured by the MO and any issues arising will be addressed promptly

- The Discos should be made to install Check Meters at all the trading points, to enable reconfirmation of measurements of the energy received (by the Discos) through the Main meters.

- The manufactures of the EDMI meter has been notified of the fact that the Data Register of the meters do not have adequate capacity to store data, and therefore cannot store previous meter readings. They have also been requested to effect necessary corrections without delay. There is a plan to conclude this correction before the end of 2013.

- The MO should be requested to ensure physical sealing of all the meters installed at the trading points, to prevent unauthorized access to the meters

- The MO should rewire the outputs of the feeder CTs at Dutse and Azare 132/33KV substations to ensure that they do not pass through the Transducers. This will enable the metering of the trading points and collection of accurate data for the settlement process. In as much as this is urgent, it may not be achieved before TEM.

- The Discos should arrange for VTs on all the outgoing feeders, to provide the voltage signals for the metering of the trading points. Due to the huge financial requirement, this project may not be undertaken immediately. Therefore the outputs of the incomer VTs will continue to be applied for the metering of the trading points through the use of the Automatic Voltage Selector Switch (AVSS).

- The Disco Trading Points at Elelenwo and Rumuosi 132/33KV substations should be metered by the MO without delay. Also the Silver Bird feeder at the P-H Town 132/33KV substation should be metered. The meter for the UST feeder at the same Substation should be repaired by the MO. All these can be achieved before end of December 2013

- The 33KV Guwada/Kuta feeder from the 15MVA, 132/33KV transformer at the Shiroro TS should be metered

- The meters on the Ijora Cause Way feeder, at Ijora 132/33KV substation at the CBN feeder at the Dan' agundi 132/33KV substation should be investigated and restored immediately by the MO.

- The TCN should convert the Nsukka feeder in Enugu EDC to 132KV from the present 66KV to be uniform with the rest of the country.
- The network should be developed such that feeders start and end within the same Discos, and avoid feeders cross-over. Where it is not possible to prevent feeders cross-over, the inter Disco Boundary meters should be installed at the geographical boundaries between Discos. The meters should be installed in protected cabinets where they are not exposed to dust and moisture ingress and other dangers. Where it is not possible to install the meter at the exact geographical boundary, there should be adjustments for the possible technical losses between the actual meter location and the boundary point
- The reasons for the wide discrepancies between the incomer energy and the sum of the energies on the associated feeders in Delta TS, Effurun TS, Irua TS, Akure TS, Amukpe TS, Yola TS, etc should be investigated by the MO. A very common reason is a change in the ratios of the CTs from those the meters were originally programmed with. The MO should insure that the incomer energy is not more than 2% higher than the sum of the associated feeder energies. Also the TSP should always notify the MO before any changes are made in the network configurations at the T/D interfaces
- The MO is the responsible party for ensuring compliance with the Metering Code. NERC should consider requiring the MO to submit periodic compliance reports showing the status of punch list items, including actions required by MO as well as Market Participants, problems encountered, corrective actions to be taken, and the schedule for remaining work to be done.

2.3 Metering for Substation Consumption

A generator gets paid for all the energy and capacity it sends into the transmission grid, irrespective of how much of the power that gets to the consumers. This means that if most of the power generated get to the consumers, the average price of power is less. Conversely, the average price of power is higher if less of the power generated gets to the consumers.

As part of price regulation, performance drive and consumer protection, the NERC put a cap on the losses that can be passed through to the consumers at various segments of the electricity network. In actual fact, the energy losses at the transmission network, is as much as 12%, but the cap placed on TLF for tariff design by NERC is only 8%. This means that out of the 12% of the energy lost in the Transmission network, only 8% is passed on to the end-user tariffs, while the Discos are made to bear the difference of 4%.

This extra 4% paid by the Discos, that cannot be recovered from the consumers though the tariffs, is capable of disturbing the commercial equilibrium of the electricity market.

The TSP charge is based on the power sent across the Transmission/Distribution (T/D) interface, and not on the power received across the Generation/ Transmission (G/T) interface. This is a market strategy to drive performance in the transmission network operation and maintenance by the TSP.

Apart from the energy losses on the network due to the impedances of the transformers and lines, other sources of the high TLF include materials used for construction, workmanship and energy consumed in the transmission substations

Substation energy metering is a strategy developed by the MO to address the issue of high TLF which is passed on to the Discos through wholesale Tariffs.

2.3.1 TEM Requirements

The requirements on the substation metering for the efficient implementation of TEM include the following:

- The meters shall be installed at the LV side of the station service transformer. In the case where there is another source of supply to the station, the meter shall be located at the entry point of such supply into the station.
- The substation meters are not trading point meters. Therefore, there is no need for check metering systems to verify the measurements of the substation meters
- The meter accuracy class shall be 0.5 or 1.0
- The meters shall be static and programmable
- Meters shall be physically sealed
- The substation meters shall be read monthly by the local Discos. The readings should be used to prepare invoices to the TSP for energy consumed at the substation. The invoices should take into consideration the 1% of the energy received across the G/T interface, allowed by NERC for TSP's station services. The net invoice should be paid by TSP to the local Discos, who are made to assume the risk of the extra energy losses that are not captured in the end-user tariffs

This way, the possible shift of the commercial equilibrium of the market due to payment, by Discos, for losses in excess of that allowed in the tariffs, is minimized. Apart from achieving a possible reduction in TFL, this programme ensures discipline in the use of electricity in the transmission substations.

2.3.2 Status of the Substation Metering

The status of the transmission substation consumption metering system is as highlighted below:

- The Substation Meters are located at the LV side of the station service transformers.
- All the meters are of accuracy class 0.5 or 1.0.
- The meters are either Skipper or Premium Entity, which are of static types and are programmable.
- The meters are physically sealed to avoid unauthorized access.
- The meters are not read by the local Discos. This is due the fact that the need has never arisen , and they (the Discos) have not been requested to do so.
- A good number of the meters are not working.
- There are no meters to measure the consumptions in all the substations in Bauchi Region.
- There are no substation consumption meters at Dutse and Azare 132/33KV substations.
- There are no meters in the new substations like Elelenwo, Rumuosi, etc.

2.3.3 Gaps to be addressed for TEM

The gaps in the substation consumption metering system which must be addressed for the initiation and efficient implementation of TEM are as follows:

- The substation consumption meters are not read by the local Discos, and no invoices are raised for TSP on energy consumed in the substations.
- The meters for a good number of substations are not working.
- There are no meters to measure the consumptions in all the substations in Bauchi Region
- There are no substation consumption meters at Dutse and Azare 132/33KV substations
- There are no meters in the new substations like Elelenwo, Rumuosi, etc

2.3.4 Action Plan to Remediate Gaps

- The Commission should request the Discos to identify the substation meters within their license areas, read such meters monthly along with the revenue meters and produce bills based on the meter readings for payment by the TSP. The 1% of the energy passing through the station has been allowed by the Commission for station supplies. Any energy in excess of this 1 % should be paid for by the TSP in respect of the station. This 1 % should be removed from the meter reading before producing the bills.
- The meters for a good number of substations are not working. Typical examples are:
  - Abakaliki 132/33KV substation in Enugu Disco
  - Kumboso 132/33KV substation in Kano Disco
  - Delta 1, 132/33KV substation in Benin Disco, etc
- The MO should draw up a programme to go round the country to activate all the substation consumption meters. Where the meter is bad, it should be repaired or replaced, depending on what is found wrong. Where there are no meters, like in Bauchi Region, Dutse and Azare, Elelenwo and Rumuosi, meters should be procured and installed by the MO.

2.4 Meter Security and Data Access

2.4.1 TEM Requirement

The requirements for sealing meters and access to metering data are shown in the Metering Code. The Commercial Meters are supposed to be sealed by or on behalf of the Market Operator and, if necessary, the Associated User, except where sealing is impossible or impractical. No seal can be broken or removed except in the presence of, or with the prior consent, of the owner and the Market Operator. In addition all meters and metering equipment, where practicable, must be made secure, if necessary by making the lock and keys subject to similar access restrictions.

Physical access to meters and metering equipment is restricted to personnel who are required to have such access. A record of any such access is maintained by the Market Operator and the user on whose premises the meters and metering equipment are positioned. The owner of the Metering Systems will allow reading of the Meters by the Market Operator. The owner of the Metering System will change data and settings within its metering equipment only in the presence of the Market Operator, or with the written agreement of the Market Operator.

2.4.2 As-is State

The trading point meters are currently being secured via the use of numbered seals that are installed on the meters. According to current rules, the MO and SO representatives are required to be physically present prior to breaking the seal and making any adjustments after which another numbered seal will be installed on the meter. Both MO and SO are required to store records of

these seal numbering and related records. Our field visits revealed that some of the meters at the audited sites are not sealed.

2.4.3 Gaps for Initiation of TEM

The use of the physical seals and location of the meters in generally accessible areas constitute weak detective controls and should be addressed immediately. There is a significant risk of data breach on the meters. There is a significant risk of data repudiation, abuse of data, unauthorized manipulation of the meter data records, calibration etc. Several meters in the audited sites were not sealed at all.

2.4.4 Action Plan to Address Gaps

We recommend introducing strong preventive controls that enable security of the meter, its calibration and operation, and the meter data records. The data generated by the meters is the initiation of the payment processing cycle and it is critical that this data is secured. Non-compliance with this recommendation will likely lead to future data repudiation issues, litigation, and probable fines from the regulating authorities.

2.5 Summary of Derogations on TP Metering Systems for Initiation of TEM

The under listed are the proposed derogations to enable initiation of the TEM without further delay. This is necessary because of the time and financial resources needed to meet the required TEM conditions. It is expected that as the Market progresses in the TEM, the TEM conditions will be achieved and derogations will no longer be necessary.

- Inter Disco boundary metering system: Most of the boundary meters have been installed at places other than the geographical boundaries of the Discos. In line with the MC, there should be loss adjustments to compensate for the variations in the locations of the meters. This is a project that may not be completed before TEM. Therefore, pending the loss adjustment in respect of all the Inter Disco boundary metering systems, the meters should be operated as presently installed, while percentage sharing of the energy is agreed between the Discos for settlement by the MO. However, Discos should be advised to reduce the prevalence of and need for inter Disco boundary metering by ensuring that feeders start and end within the same Discos.

- The 33KV interconnections with Niger Republic from Birnin-Kebbi and Damasak are not dedicated solely to the international load. Therefore the meters at the sources of the feeders measure energy consumed within Nigeria, as well as the energy consumed in Niger Republic. Meters should be installed at the international boundaries, at the Border Posts where protection of the meters from theft and weather can be reasonably guaranteed

- Pending the implementation of the above, which may require some time to achieve, the meters can be operated as currently done, while meter readings are shared at an agreed ratio between the relevant utilities

- Substation metering in Bauchi Region cannot be implemented now as a result of the security issues in the North Eastern part of the country. These meters can therefore not be in place for TEM. The meters can be installed when ever contractors are more comfortable to take up the jobs

- Output of the feeder CTs at Dutse and Azare 132/33KV substations should be rewired to by-pass the Transducers, which prevent the metering of the trading points. However, this may not be achieved before TEM. The reliance on the incomer meter reading for the settlement process will continue until correction on the feeder CT outputs is effected

- A major capital investment is required for the installation of VTs at all the feeders (Distributor TPs). Also some time will be required to install the VTs, assuming there is available fund to purchase them. It is therefore not possible that all the trading point meters will be operated from different VT windings before the initiation of TEM. The incomer VTs will continue to be used to operate the trading point meters through the AVSS.
- The ITRON and EDMI meters can be made to record the MW data after every 1hr, average the hourly MW over the month and store the average in the memory at 0.00hrs of the 1st day of the new month, for retrieval as one data. This situation may not be achieved before the declaration of TEM. Therefore, the market should be operated with the manual reading and recording of the MW data for settlements.
- Check meters should be installed at all the trading points, but given the investment requirements, that may not be achieved before TEM. The Transition Market can be declared, while the participants are allowed about 24 months to install the check meters.

3 COMPLIANCE WITH MARKET RULES FOR METER DATA COLLECTION AND MANAGEMENT

The Market Rules set out the responsibilities of the Market Participants, the TSP, SO and the MO in relation to trading, despatch and contract nominations, metering, settlement and payments in the electricity market. It also provides the framework for an efficient, competitive, transparent and reliable Wholesale Electricity Market

One of the responsibilities of the Market Operator, assigned by the Market Rules, is to administer the Market Metering System, which consists of:

- Meters for each trading point of participants and the associated instrument transformers (CTs and VTs), Automatic Voltage Selector Switch (AVSS) and cabling.
- A system that integrates and stores the measurements for the meters. The information storage capacity in the memory of such meters should be of at least 9 months
- A communication system to access and read the meters remotely

All data calculations for settlement in the Market shall be measured through this Commercial Metering System. The data (Energy in MWh and Capacity in MW) are the same for all market participants. Therefore, the rules for meter data collection and management for Distributor load consumption and Generator energy delivery, are the same.

The Market Rules also, outlines the procedure for the collection and management of the meter data.

3.1 Meter Data Collection and Management

The Distributors extract power from the grid and therefore participate in the electricity market as purchasers, while the Generators inject power into the grid and participate as sellers in the market. All the data for power extracted and power injected are measured and collected through the Metering Systems

3.1.1 Requirements for TEM

The requirements of the Transitional Electricity Market (TEM) on the participant commercial meter data measurement, collection and management, are as follows:

- The Market Operator shall identify each participant trading point with the corresponding metering system for collecting and collating data to be utilized in the settlement process
- The MO shall draft and implement the metering procedure, detailing among other things, the methodology and time table for reading and submitting meter data. Every participant is obliged to follow the procedure and shall submit data to the MO within the deadline stipulated. In line with the metering procedure , the methodology and time table for the reading and submission of data are as follows:
  - Meter reading shall be done jointly by the participant representative and the System Operator
  - The joint reading shall be done by scrolling the meter to retrieve the reading at 0.00hrs of the 1st day of the new month, already stored in the meter. Reading minutes shall be prepared and signed by both parties.

- Both the participant and the SO shall collate the readings and submit meter readings to the MO not later than the meter data submission date in the metering procedure. The collated readings shall be separately sent to the MO via E-mail, Courier or any other approved medium.
- Through a data collection system for remote access to the information stored in the meters, the MO shall read the meters monthly, for those meters where remote reading has been implemented
- The meter data shall consist of the energy and capacity extracted from the grid or injected into the grid, at the participant connection point (s). Energy shall be the total energy received or delivered during the month, while capacity is the average of the hourly MW received or delivered over the same period.
- The reading process shall include the incomer meters at the T/D interface points (for the Distributors), to be used for reconciliations

- The unprocessed meter data received by the MO, either from the participant or through the Market Operator AMR System, shall be subjected to the validation and correction process stipulated in the Grid Code

3.1.2 Status of Meter Data Collection Process (As–is State)

The following is the status of the meter data collection process, against the requirements of the Transitional Electricity Market (TEM), as stipulated in the Market Rules and Procedures:

- The Market Operator has identified the trading points for all the participants. The corresponding metering systems for measuring power injected into and extracted from the grid, for collecting and collating data to be utilized in the settlement process, have also been implemented.
- The MO has drafted and implemented the metering procedure for reading and submitting meter data. Every participant follows the procedure and submits data to the MO within the deadline stipulated. However, the methodology and time table applied are as follows:
  - Meter reading is done by the participant representative and the System Operator monthly, but not jointly
  - The reading is done by scrolling the meter to retrieve the readings at 0.00hrs of the 1st day of the new month, already stored in the meter.
  - The data stored in the meters which are retrieved in the reading process are the Energy in MWh. Capacity is not stored in the meter for both the Generators and the Distributors. For the Generators, the real time MWs are manually read from the meters hourly, and recorded by the SO. For the Distributors, the real time MWs are read from the meters six hourly, and recorded by the SO.
  - Since the meter reading is not joint, there are no Reading minutes in respect of the monthly readings.
  - The participants and the SO collate their readings and submit to the MO, in line with the metering procedure. The collated readings are separately sent to the MO via E-mail or Courier. The energy readings sent to the MO are those retrieved from the meters, while the MW values sent in respect of the Generators, are the daily peaks, averaged over the month. The MW quantities used by the MO for settlement calculations, in respect of the Distributors are derived from the energy quantities sent by the participants and the SO.
  - The data collection system for remote access to the information stored in the meters is yet to be implemented. Therefore, the MO is currently unable to read any

of the meters remotely. However, the MO has developed a system for remote meter reading, automatic data validation and correction, but the system is not ready for commissioning yet. The system developed consists of:

- Meters installed at the Participant trading points, with communication Modems
- GLO GPRS Network
- Data collection system developed around the MV-90 platform

– The reading process includes the incomer meters.

- The unprocessed meter data received by the MO from the participants is usually subjected to manual validation and correction processes

The MO intends to automate reading of grid meters to the extent possible, and has installed the MV-90 data collection and analysis tool for that purpose. The system is used to retrieve interval data, perform data validation, data editing, aggregation, reporting and graphing. Data can be retrieved using GSM and GPRS over a wide area network

The MV-90 was designed as a true multi-vendor system to support metering hardware supplied around the world for electric utilities. MV-90 now supports more than 160 devices with interrogation using GSM, GPRS, and/or manual collection of data

Though, there are only two metering hardware currently in the Nigerian Electricity Market (the ITRON and EDMI meters), the MV-90 is designed to support more meters which may be implemented in the future.

The system development is essentially completed. A major outstanding is the reprogramming of the EDMI meters to be capable of storing previous meter readings at a prescribed time, and for as long as required. The ITRON meters can, at the moment, be read remotely through the system, while the EDMI meters cannot, due to the above reason. It should be noted that only the MWh data can be obtained from the ITRON meters remotely. The MW data cannot, at the moment.

The Architecture of the metering system developed by the MO is as shown in Figure 3-1.

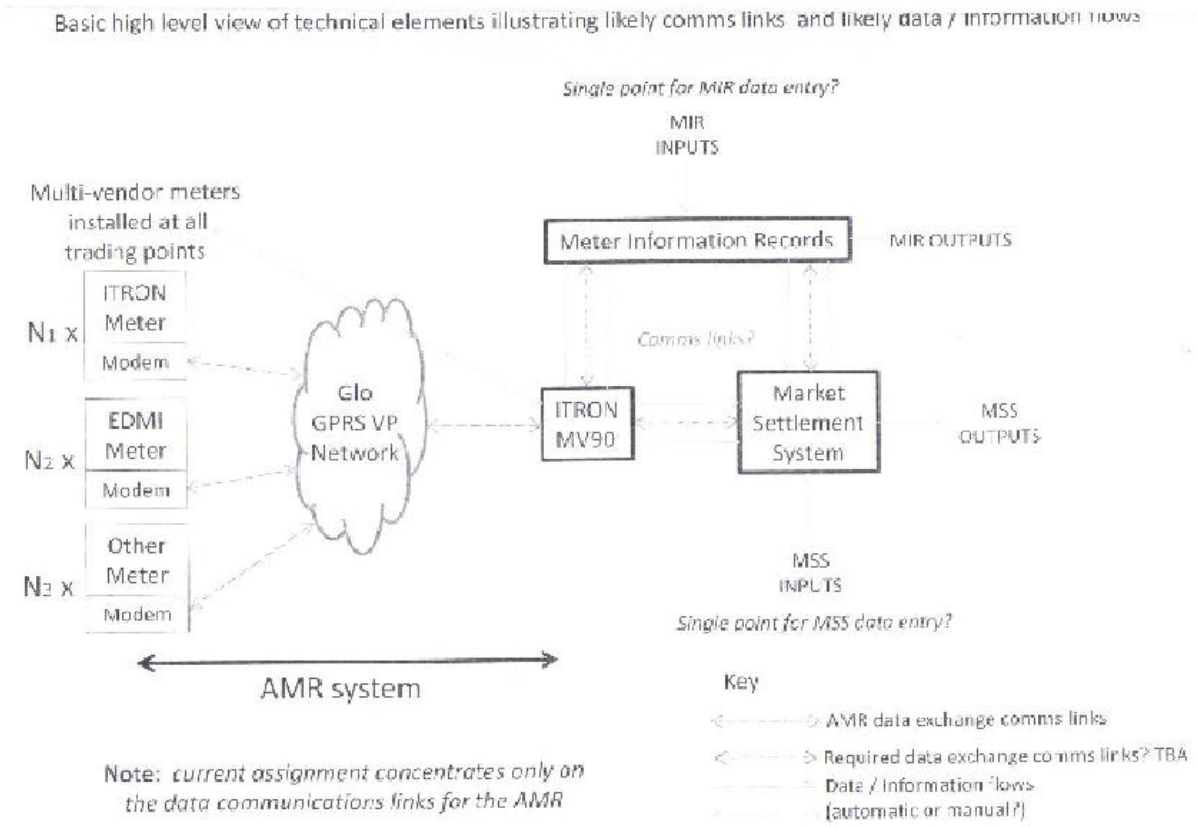


Figure 3-1: Architecture of MO Metering System

3.1.3 Gaps in the Meter Data Collection and Management Process for TEM

The Gaps in the Data collection and management process is established by considering what is implemented against what is stipulated, for the operation of the Transitional Electricity Market (TEM). The identified gaps are as follows:

- Meter reading is done by the participant representatives and the System Operator monthly, but not jointly as recommended in the Market Procedure.
- Since the meter reading is not joint, there are no Reading minutes in respect of the monthly readings.
- The data stored in the meters which are retrieved in the reading process are the Energy in MWh. Capacity is not stored in the meter for both the Generators and the Distributors, and therefore not retrieved in the reading process.
- The energy readings sent to the MO are those retrieved from the meters for both the Generators and the Distributors, while the MW values sent for the Generators are the daily peaks, averaged over the month. No MW values are sent in respect of the Distributors.
- The data collection system for remote access to the information stored in the meters is yet to be implemented. Therefore, the MO is currently unable to read the meters remotely.

3.1.4 Action Plan to address the Gaps

The actions to be taken on the gaps to ensure that the process of data collection and management comply with the TEM conditions are:

- The Commission should activate the implementation of the Market Rules and Procedures in the operation of the Nigerian Electricity Market, and the Market Operator should ensure compliance with the process of data collection and management.
- Apart from joint reading, the MO should also insist on Reading minutes in respect of the monthly meter readings.
- Capacity (MW) is a real time quantity and cannot be stored like the Energy. However, the meter can be made to integrate the MW quantities over every 1hr, with the hourly quantities averaged over the month. The average can be stored at 0.00hrs of the 1st day of the new month and retrieved as one data, like the Energy data, in the reading process.
- Like the energy readings, the capacity readings sent to the MO for the settlement process, should be those retrieved from the meters for both the Generators and the Distributors.
- The MO should be made to conclude the development of the data collection system for remote access to the information stored in the meters. However, the system cannot be activated if the meters are unable to store the MW data as one quantity. Also, the system cannot be activated if the EDMI meters are not programmed to store previous readings for as long as 9 months . It is only when the data collection system is activated that the MO can read the meters remotely, to enable him compare with the readings from the participants and the SO

It should however, be noted that the efficiency of the AMR system is subject to the following conditions:

- Efficiency of the communication system in use
- The grid network conditions. Feeder and substation outages disrupt the operation of the AMR system
- The condition of the trading point meters

Due to the above reasons, the reading of the trading point meters through the AMR cannot be guaranteed beyond 70 to 80%, unlike in more advanced countries, where success of meter reading can be guaranteed up to 95 – 100%.

The following are some recommendations on the Trading Point Metering Systems, in respect of all the Market Participants for the efficient implementation of TEM:

- The possibility of faults in the Trading Point Metering Systems, like other problems, disrupting the operations and efficiency of the AMR system make it necessary for the maintenance and operation of the metering system to be outsourced to a private company with the required expertise, for prompt restoration and sustained availability of the system. At the moment the MO operates and maintains the system, but efficiency is affected by a number of reasons, such as lack of adequate funding , disappearing capacity and expertise among the workforce, lack of adequate and relevant training, etc
- Most staff interacted with in the course of the field investigations appear not to be conversant with the Market Rules, Market Procedure, the Grid Code and the Operational Procedure. Therefore some training is recommended for the Participants in these areas.

- The necessary adjustments for technical losses due to the installation of trading point meters at locations other than those prescribed, should be outsourced to competent contractors to ensure efficiency and fast track implementation

3.2 Communicating, Tracking and Reporting of GenCo/IPP Contract Quantities

3.2.1 TEM Requirement

Under TEM, the Market Operator is responsible for calculating the contract market quantities at the end of each month. The MO must keep records of the following quantities, as specified in the PPAs between NBET and GenCos/IPPs: energy sold, generation capacity sold, uninstructed generation (which may be priced different from instructed generation if allowed under the PPAs), number of startups and time on hot standby. All of these quantities must be tracked for payment purposes under the PPAs, although it should be pointed out that the latter two items, number of startups and time on standby, are not specified in the current version of the Market Rules. The SO is responsible for recording, in respect of each Generating Group, the quantities that are used to calculate payments to the generators, and passing this information to the MO.

3.2.2 As-is State

The MO/SO currently calculates GenCo contract market quantities using the following processes:

- Energy sold – As described earlier, the SO reads the meters at the GenCo trading points at the end of the month, records the quantities and sends the information to the MO. At present, half hourly readings are not generally recorded or transmitted to the MO. Half hourly recording of meter data will be facilitated by the completion of the AMR implementation.

- Generation capacity sold (generator Available Capacity) – Current practices for tracking generator Available Capacity are wholly inadequate, as described elsewhere in this report.

- Uninstructed generation – The Market Rules say that the monitoring system and compensation mechanism for uninstructed generation shall be developed and tested by the Market Operator during the first six months of the Transitional Market, and shall be implemented and maintained from the seventh month. This will require half hourly accounting for uninstructed generation. Nothing is currently in place to track uninstructed generation.

- Number of startups – currently not tracked, although the information may be recorded in log books.

- Time on hot standby – currently not tracked, although the information may be recorded in log books.

3.2.3 Action Plan to Address Gaps

- A working group consisting of SO/MO, NBET and representatives of GenCos and IPPs should be set up to address the current gaps in tracking and calculating GenCo contract market quantities.

- SO/MO should establish a scheduler's desk at NCC that will operate during the day shift. The scheduler is responsible for ensuring compliance with Market Rules and contracts for recording, collecting, tracking and confirming operational data.

3.3 Communicating, Tracking and Reporting of DisCo Contract Quantities

3.3.1 TEM Requirement

Under the terms of the Vesting Contracts between NBET and DisCos, NBET charges the DisCo for generation services based on the Disco Share Dependable Capacity of the available system generation, and associated Gross Energy Output. These are expressed as fixed percentages as determined by NERC. DisCos pay for transmission services according to the NERC regulated tariff, which uses energy consumption as the billing determinant. Energy consumption is also used as the billing determinant for charges from other services providers.

The Vesting Contracts require the following scheduling notices associated with contract quantities, and the Grid Code Section 7 contains additional relevant requirements for information exchange between the SO and Market Participants during normal and emergency market operations:

- Buyer's (DisCo's) Forecast – From the Effective Date, Buyer shall notify Seller (NBET) and System Operator (or revise any such information previously given) of the forecast demand for each Settlement Period ("Buyer's Forecast") of the following Day no later than 16 hours prior to the beginning of each Operating Day ("Declaration Deadline"). The Buyer's Forecast shall not exceed the Disco Share Tested Capacity.

- Seller's Nominations – Seller shall issue to Buyer not later than 5 hours before the start of each Operating Day the Nominated Quantity projecting non-binding requirements for Gross Energy Output that will be delivered to Buyer for each Settlement Period of the next Operating Day.

- Buyer's Obligation – Upon receipt of the Nominated Quantity, Buyer shall use its Best Endeavours to adjust its operation to accept such Nominated Quantity. If Buyer is unable to do so, Buyer shall immediately inform Seller, the System Operator and the Market Operator, and any adjustment to balance the Grid will be directed by the System Operator, save that Buyer shall remain liable for the Disco Share Capacity Payments, Energy Payments and Disco Share Start-Up Payments. Provided that, where the Seller sells the Nominated Quantity to a third party, the Buyer shall only be liable for the shortfall (if any) between the amount paid by the third party and the amount the Buyer would have paid had it received the Nominated Quantity.

Under the terms of the Vesting Contracts, the market invoice to the DisCo is supposed to specify the Disco Share Dependable Capacity made available to the DisCo and the associated Gross Energy Output delivered to DisCo for the previous month.

3.3.2 As-is State

At present, there is a single contract quantity used by the MO to develop market invoices to the DisCo, the monthly actual energy consumption. DisCo energy consumption is metered and the metered quantity is used as the billing determinant for generation and transmission charges, as well as regulatory and other administrative charges. In most cases, Disco's actual energy consumption differs from the Vesting Contract DisCo share allocations. For example, Table 3.1 shows the imbalance energy results for the month of July 2013. For this month, the imbalance energy ranges from and over allocation of 50% in the case of Enugu DisCo, to an under allocation of 38% in the case of Kano DisCo.

Table 3.1: Imbalance Energy Totals for July 2013

DisCo	Regulated Allocation of Available Energy,%	Actual Allocation of Available Energy,%
ABUJA EDC	11.500	13.880
KANO EDC	8.000	4.038

DisCo	Regulated Allocation of Available Energy,%	Actual Allocation of Available Energy,%
KADUNA EDC	8.000	6.398
IBADAN EDC	13.000	13.897
JOS EDC	5.500	4.797
EKO EDC	11.000	8.837
IKEJA EDC	15.000	14.741
PORTHARCOURT EDC	6.500	6.733
BENIN EDC	9.000	14.183
YOLA EDC	3.500	1.887

The provisions of the Vesting Contracts and the Grid Code Section 7 regarding scheduling notices and information exchange between the SO and Market Participants related to DisCos share allocations are not generally followed. During field investigations, the Nexant team received multiple complaints from DisCos around load allocation and allegations of the following deficiencies:

- There is a lack of communication from the National Control Centre (NCC) on grid generation and capacity variations. Load allocation messages are not relayed to the DisCo HQ, and as a result there is no way to ascertain the quantity Disco should get or is entitled to. In a situation of this nature, monitoring/tracking of load is impossible.
- There is a lack of communication from the SO at the Area Control Centre (ACC) on load allocations to the Discos and on the discrepancies with expectations of the Discos.
- Data exchange interfaces with TCN is largely in the form of voice messages and control room logbook entries. There is actually no forum for comparison of operational notes.
- It is alleged that TCN/SO opens feeders "indiscriminately" during frequency excursions. It can be assumed that TCN/SO does this because of grid security considerations – the Grid Code allows this. The same Grid Code makes it mandatory that explanations be offered after stabilization. This rule must be enforced.
- SO staff interacted with are not conversant with either the Grid Code or the Market Rules.

3.3.3 Action Plan to Address Gaps

- Continuation of the present practice of using DisCo monthly actual energy consumption as the single billing determinant for market charges to the DisCos seems like a practical approach for TEM, at least in the early going. However, this is not consistent with the Vesting Contracts, which require tracking of Disco Share Dependable Capacity and DisCo Share Gross Energy Output to determine charges. NERC should address this discrepancy and ensure a collective understanding of market charges and billing determinants.
- There should be regular, monthly interface/coordination meetings between TCN (TSP/SO) Regions and the Discos within their areas of jurisdiction to deliberate, amongst others, the followings:
  - Grid discipline;
  - Grid Code compliance issues;
  - Voice and data communications protocol;
  - Load allocation/despatch arrangements;
  - Load shedding schedules;
  - Outage management etc.

- A procedure that ensures the concerned Disco gets to know the quantum of power on the grid and its share thereof, in accordance with the Vesting Contract, needs to be put in place before declaration of TEM. At a minimum, NCC's daily operations report should be sent to MD/CEO's of all successor companies. The relevant provisions of the Grid Code should also be respected.

- SO/MO/NBET should develop a detailed operating procedure for scheduling, operating, tracking and communicating DisCo contract quantities.

- In the interim there is need to encourage the culture of constant verbal communication of events between stakeholders; such communications should be entered into Control Room logbooks and thereafter entered into computer data bases.

- As soon as practicable – in fact with immediate effect – after daily load allocation schedule is received from NCC by the Transmission Region, the Regional Operations Officer should appropriate the load according to NCC document/instructions and circulate to MD/CEO of the Distribution Company and/or relevant/designated Disco formations. This should be tested before declaration of TEM.

- NERC should consider requiring an independent evaluation of SO performance in load allocation and related communications with Market Participants, including recommendations on improvements in these areas. NERC should require the SO to submit regular compliance reports showing the status of targeted improvements, as identified in the independent evaluation. The regular compliance reports should cover actions required by SO as well as Market Participants, problems encountered, corrective actions to be taken, and the schedule for remaining work to be done.

- Field staff should receive training on the requirements of the Grid Code and the Market Rules.

3.4 Telecommunications and IT Infrastructure for Meter Data Collection and Management

3.4.1 TEM Requirement

The Market Operator is responsible for the development, implementation and testing of the systems and procedures to implement the Market Rules for the Transitional Stage. A robust telecommunications and IT infrastructure for meter data collection and management, both in MO HQ and in field locations, is vital for proper functioning of TEM. The requirements in these areas are not laid out in the existing rules and procedures, as it is an internal matter for MO/SO to implement. The following sections provide a review and comparison of the current state vis-à-vis best practices.

3.4.2 As-is State

- The MO collects meter data both electronically from the automatic monthly AMR meter data transmittal by the field trading point meters (via GPRS mode of transmission), manual submissions by the DisCos and daily reports from the SO's daily Operational report (via email).

- The enterprise AMR system consists of a Hub and Spoke network topology where the trading point meters (spoke) communicate with the AMR system in the Market Operator office (hub). The AMR reporting system (hub) consists of the Actaris metering system. Meters at the trading points are configured to transmit data to the AMR reporting system. The AMR reporting system also has the ability to probe and request for on-demand data from meters at the trading point. The trading point meters are connected to the AMR

reporting system via GSM and GPRS. However, during interview with the MO staff, the system is currently configured to default to the GPRS medium of transmission.

- The ITRON meters are currently transmitting data via the GPRS medium while the EDMI meters are yet to be configured to transmit data via the GPRS system to the AMR reporting system.
- The application used to manage and administer the AMR reporting system is the ITRON-MV 90 software. The MV 90 is a solution for interval data collection, management and analysis. The AMR system and related equipment are located in the AMR room at MO HQ.

3.4.3 Gaps for Initiation of TEM

The following gaps exist regarding Information and Communications Technology (ICT):

- There is no evidence of an ICT corporate governance structure and thus there is insufficient internal control processes to protect the meter data records and other critical data from data repudiation, malicious use from unauthorized users, data loss, abuse etc.
- Server and data infrastructure hosted by various departments are distributed and located in each separate department location which increases the probability and risk of data loss, abuse of data, malicious use from unauthorized users, data repudiation etc.
- Access to data and system resources are generally un-auditable and unsecured
- Access to critical areas such as server room, AMR room and Treasury where confidential and critical data are stored is not securely restricted and auditable.
- The existing email system is currently outsourced and thus will be difficult to implement e-discovery processes as required by the Market Rules Section 47.1.3.
- There is no evidence of an Electronic Document Management System (EDMS) or other alternative to enable document archival compliance with market rules Section 47.1.3. Storing documents is hardcopy paper format is not sufficient for compliance as paper print media degrades over time among other constraints.
- There is evidence that additional skilled ICT personnel are needed to administer, manage and secure the enterprise network infrastructure envisioned in this report.

The following gaps exist for Automatic Meter Reading (AMR):

- The AMR system is not fully functional at present. As noted earlier, some of the grid meters are yet to be equipped with AMR. For those meters on AMR, the AMR readings are used as a backup to manual readings.
- There is no redundancy or resilience at the AMR Hub (AMR system located in the MO's office). If there is an AMR system outage, data reading across all the trading point meters can no longer be centrally collated for the submitted data verification and processing by the Market Operator. This will severely impact the ability of the MO to generate monthly settlement statements, thus payments to stakeholders etc.
- Access to the AMR system is via a workstation attached to the AMR server. The workstation is vulnerable and highly insecure. There is also a significant risk of data loss if the workstation is compromised, broken or stolen.

3.4.4 Action Plan to Address Gaps

The TEM and subsequent phases of the Electricity Market will have a very high dependency on accurate and secure data for the entire privatization exercise implementation to be successful. This requires extensive Internal Control process across all departments to ensure all data are accurate, secure, highly available and free from data repudiation. Data is not useful if it is compromised, inaccurate or unavailable as a result of systemic failures.

The following actions are required to address identified gaps:

- An ICT corporate governing structure should be created to ensure that urgent and critical ICT requirements to support the operations of the NBET are identified and implemented. Such requirements shall include the security and availability of business data and computing resources etc

- The MO should initiate processes and procedures to establish required levels of internal control required to secure all data obtained and processed by the MO.

- We recommend the centralization of server resources across the various departments. Access to these resources should be authenticated against an enterprise directory service. This ensures that data access to these resources is authenticated, audited and secure.

- We recommend that all data obtained, received, processed and ultimately stored be compliant with Section 47.1.3. of the Market Rules.

- We recommended (at the minimum protection level) that the server room be relocated to a special fit-for-purpose room in a restricted part of the building. Casual human traffic (walking or strolling) along the corridors in this location should be highly controlled and restricted. Use of biometric-access control devices complemented by the use of Video Surveillance camera and recording equipment shall constitute the minimum level of site and server room protection

- We recommend the immediate creation of an ICT policy and standards document to cover ICT operations across the enterprise network. Such documents shall include User Acceptable Use policy, End-point security policy, server security policy, data retention policy to include the various categories of data types, Recovery Point Objective (RPO), Recovery Time Objectives (RTO) etc. This will aid in setting the basic requirement standard on how to manage and secure all data obtained, processed and stored in the course of the business processing cycle.

- The MO needs to take the necessary steps to fully implement AMR as the primary system for collecting grid meter data and feeding the data to the settlement system. Completion of the AMR system should be structured as a project with a designated project team, clear delineation of roles and responsibilities and formalized schedule of activities and completion milestones. Training should be integrated with the project. Given the short time remaining before initiation of TEM, and the specialized nature of the AMR system, MO should give due consideration to outsourcing management of the AMR system to a qualified contractor.

- We recommend the immediate purchase, installation and configuration of at least one redundant AMR (hub – ACTARIS System) to be installed in the MO's office. This is required to provide the minimum level of AMR recording redundancy to support the business process cycle in the event of an unplanned AMR hub outage.

- We recommend the immediate cessation of critical business data submission between the System Operator and Market Operator via email or telephone communication. All energy data reporting from the System Operator shall be distributed to stakeholders by hosting on a private built-for-purpose web portal owned and operated by the System Operator.

- Similarly, all Market Operator related data reporting and communication shall be distributed to stakeholders by hosting on a private built-for-purpose web portal owned and operated by the Market Operator.
- Data partitioning by respective data owners is critical for data management, ownership, auditing, accountability and regulatory compliance purposes.
- The proposed web portal shall be located on a private network (not hosted on the public network) and ONLY pre-authorized users and stakeholders shall have access to the web portal. All other users' access shall be denied. NOTE: This data is confidential and relates to Nigeria's national Critical Infrastructure.
- Access to the proposed secure web portal for submitting and accessing confidential information shall be integrated with a multifactor authentication server platform. Users shall be provisioned and pre-assigned with a user token device generating one Time Passwords (OTP) which shall ensure non-repudiation of data.
- Submitting business data via the proposed secure web portal significantly reduces the risk of data repudiation, omission, and unauthorized manipulation of data, disputes and penalties by the corresponding regulating authorities. In addition, the collection and processing of submitted data in "structured data" format presents new capabilities to the MO for real-time processing, Business Intelligence, data mining, predictive intervention, proactive maintenance, data reporting, data archiving in compliance with Section 47.1.3. of the Market Rules etc.
- We recommend the creation of a highly detailed Business Continuity plan. A required Condition Subsequent of the Business Continuity plan shall be the establishment of a remote Business Continuity Center (BCC). This shall ensure that in the unlikely event of unavailability of the production datacenter site or service, data processing shall continue and not disrupt the business processing cycle of the Market Operator. The type of Business Continuity Centre ("hot", "warm" or "cold") shall depend on the Market Operator's Risk Assessment and Business Impact Analysis report.
- We recommend that hosted e-discovery services be procured as part of the hosted email service contract. This ensures that all incoming and outgoing emails are archived and available for retrieval in the event of the discovery process in civil litigation matters.
- We recommend augmenting the existing ICT staff with competent and skilled ICT resources with clearly defined roles and responsibilities to maintain the enterprise network infrastructure. Certain aspects of the ICT operations may also be outsourced due to the short time frame but the procurement of outsourced services shall be required to take into consideration the high levels of security and data confidentiality required.

4 MO/SO DETERMINATION OF AVAILABLE CAPACITY FOR GENCO CAPACITY CHARGES

Under the PPA between NBET and the Successor Company GenCos, "Available Capacity" means the net generating capacity in MW that the GenCo would be able, in the absence of fuel constraints, to make available for despatch at the Delivery Point. Capacity Payment should be computed on the basis of actual Available Capacity determined by the SO for the Settlement Period and the applicable capacity charge under the tariff.

"Dependable Capacity" is defined as the Available Capacity of the Plant in each Settlement Period, adjusted to Reference Site Conditions, provided that the Dependable Capacity for any Settlement Period may not exceed the then-current Tested Capacity.

4.1 Reporting and Tracking of Available Capacity

4.1.1 TEM Requirement

GenCo and SO should maintain operating records on a half hourly basis that are needed to track Available Capacity. The SO will need to track and report the following data relating to system operations and despatch so that the MO can determine the quantities used for GenCo capacity charges in monthly settlements:

- Tested Capacity, pursuant to capacity test conducted at least annually.
- Declared Capacity, which GenCo claims is available for the following day.
- Instructed generation, which is known variously as:
  - In the PPAs, instructed generation is called "Nominated Quantity."[1]
  - In daily system operations, instructed generation is the quantity shown in the day ahead schedule sent out by the SO, or as changed during real time operations.
- Generating capacity at the Delivery Point, referred to in the PPA as "actual recorded capacity."

In addition, the following data relating to determination of Available Capacity must be tracked by SO/MO/NBET, as it is used in the determination of Available Capacity under the PPA:

- Fuel availability to the GenCo
- Ambient temperature at the Plant

4.1.2 As-is State

The SO is responsible for tracking the data required for determination of Available Capacity. The following processes are currently in use:

- Tested Capacity – Results of capacity tests are recorded by SO/MO.

[1] The PPA provides for NBET to determine the nominated quantity on an hourly basis, although in practice it is expected that the SO may retain this responsibility, at least in the early going until NBET is able to fully participate in the complexities of system operations at the National Control Center.

- Declared Capacity – As part of normal daily operations, Declared Capacity is supposed to be sent by the GenCo to NCC and recorded in despatch logs. The present mode is that plants nominate their "available" units with their full capabilities. Nomination is done via GSM telephone and thereafter entered into both the station's and NCC's log books; rarely are nominations received in writing from the power stations. Anecdotal field observations suggest there may be some indiscipline in respect to the capacity declaration requirement. For example, at Egbin Power Station we were told that availability is declared every morning and document sent to NCC but a copy of such nomination document that we reviewed does not include NCC on the circulation list.

- Instructed generation – Due to generation shortages, all available units are maximally despatched by National Control Centre. There are occasional reductions in instructed generation during transmission constraints. The NCC collated day ahead nomination, referred to as Tentative Generation Schedule, is prepared on a daily basis. Despatch instructions from NCC are by mobile phone and they are entered in the log books at both NCC and GenCo.

- Actual generation output of the Plant – For purposes of measuring generation output, actual generation outputs are read hourly by the GenCo operators and relayed to NCC SO personnel. SO personnel manually read the meters at the transmission substations twice per day, at peak and off-peak times, the timing of which can changes daily based on load patterns, and provide the data to NCC.

- Fuel availability – It is very likely that the SO is aware of the fuel situation at the power plants on a daily basis. There is no formal procedure for the GenCo/IPP to report fuel availability to the SO, but this matter would be touched on during routine calls between the SO and the generator. The SO may record fuel availability in log books, but there is no formalized process for confirming fuel availability with the generator and recording the information for use in calculating capacity charges.

- Ambient temperature – To our knowledge, the SO does not track ambient temperature at the GenCo Plants.

The MO is responsible for acquiring capacity availability data from the SO that is required for settlement purposes. The data interface between the SO and the MO is the Daily Operational Report, which is prepared by NCC in Excel spreadsheet format. An example of the Report is shown in Appendix 4. The Generation Capacity Worksheet of the Daily Operational Report provides columns for the following quantities for each GenCo for the day:

- Installed Available Capacity (MW) – Tested Capacity of the Plant.

- Actual Generation Capability/Units on Bar Capability at Peak[2] (MW) – This is the GenCo's Declared Capacity, as recorded by the SO from operational records.

- Generation at Peak – This is the actual generation output of the Plant during the peak period (and this may not be the maximum output of the plant during the day in question) as relayed by the GenCo operators to SO personnel who pass on such information to NCC. We were informed that data used by the MO for calculating the billing determinants for capacity charges shown in the monthly Settlement Statements are lifted from the Generation at Peak column of the Daily Report. The MO takes the average of the daily peak readings for the month as the basis for payments.

[2] The daily operational report shows separate columns for "Actual Generation Capability" and "Units on Bar Capability at Peak," although it is observed that the quantities are the same in each column.

There is no data in the Daily Operational Report for the other parameters required for proper calculation of capacity charges billing determinants, i.e. instructed generation, fuel availability, ambient temperature.

4.1.3 Gaps for Initiation of TEM

- Under the PPAs, GenCo/IPP capacity availability is supposed to be tracked on a half hourly basis to provide the data required for calculating the monthly billing determinants. It is clear from the descriptions above that at present the recording, collecting, tracking and confirming of the half hourly operational data required for determination of GenCo capacity charges is wholly inadequate. The current practice of using the daily peak generation as the plant available capacity can no longer be tenable, whatever the reason(s) for this is/are.
- Under the PPAs, the GenCos are supposed to notify NBET and SO of fuel supply limitations. At present, there is no formal procedure for the GenCo/IPP to report fuel availability to the SO.

4.1.4 Action Plan to Address Gaps

- A working group consisting of SO, MO, NBET and representatives of GenCos and IPPs should be set up to address the current gaps in tracking and calculating Available Capacity for GenCo capacity charges.
- MO/SO requires training on data requirements for determining Available Capacity, the steps in the calculation and the associated market and operating procedures. The training should also cover the theoretical basis for capacity charges in MYTO and the PPAs.
- SO must record, confirm and report the hourly operational data that is needed to calculate generator available capacity.
- The SO should develop appropriate forms/templates for recording the required operational data in real time.
- The SO should develop a worksheet for consolidating and reporting the hourly data for all the GenCos on a daily basis. NBET has developed a spreadsheet showing all of the inputs required for calculating available capacity and capacity charges. The spreadsheet is consistent with the terms of the PPAs. The SO can use the input worksheets from the NBET spreadsheet model to report the quantities required for calculating Available Capacity. Ideally the SO should develop a seamless interface between the NBET input sheets and the forms developed by the SO for recording real time operational data.
- A procedure should be put in place for the SO and GenCo to report on a daily basis the fuel availability to the power plant, and for the SO to record and report the information to the MO/NBET.
- A procedure should be put in place for the SO/MO to confirm the fuel availability information reported by the generator, such as review of operating records, GenCo communications with fuel supplies and fuel invoices, as well as periodic site visits to confirm that fuel supply problems are outside the control of the GenCo.
- MO should develop a model to input the hourly operating data provided by the SO and calculate the monthly billing determinants for capacity charges. Since NBET has already developed the spreadsheet model, the most expeditious approach is for MO to validate NBET's model and adopt it for the MO's own purposes. The output of the Available Capacity model is then used as input to the Settlement System.

- SO/MO should establish a scheduler's desk at NCC that will operate during the day shift. The scheduler is responsible for collecting and reporting the operational data used for settlement of capacity and energy charges. The scheduler is responsible for ensuring compliance with Market Rules for recording, collecting, tracking and confirming of the hourly operational data.

4.2 Confirmation of Quantities Used for Determination of Available Capacity

4.2.1 TEM Requirement

All delivered quantities, day ahead schedules and instructions from SO and GenCos, constituting the data used for the determination of Available Capacity, should be communicated in the form of Excel spreadsheet and confirmed between the SO and the GenCo on the current or following day, if not hourly. In accordance with the Grid Code all instructions are "agreed" upon receipt, the agreement being in the form of an email.

4.2.2 As-is State

A general observation found consistently at field locations is that facility operators, whether at DisCos, Transmission Substations or GenCos, get verbal instructions from National Control Centre and these instructions are not usually followed with written confirmation from NCC, neither is reception confirmed in writing by the receiving end. Such instructions are however logged in the despatch log book. In case of dispute, proof may be difficult to establish. Current practices can be characterized as haphazard or non-existent compliance with the Grid Code requirements regarding transmittal and confirmation of receipt of operating data.

4.2.3 Action Plan

NIAF advisors have developed a draft "Instructions Recording Procedure." The SO, MO and Market Participants should now take the required steps to put this procedure into operation.

In the meantime during the early going of TEM, voice confirmation of quantities between NCC and the relevant parties may be an acceptable derogation from the Grid Code however ideally the full set of actions recommended in this report regarding IT and telecommunications systems should be implemented as soon as practicable.

4.3 MO Determination of Available Capacity for Settlement Purposes

4.3.1 TEM Requirement

SO/MO should determine the actual available capacity for each GenCo on an hourly basis, and calculate the average hourly available capacity for the month as the billing determinant for capacity charges. The SO should implement such methodology as soon as practical during the Interim Period, as the basic method applies equally whether capacity charges are calculated according to MYTO or the formulae in the PPAs.

Available Capacity is generally equal to, but may be less than, the Declared Capacity. If the Plant is fully despatched by the System Operator, i.e. instructed to generate its Declared Capacity, then the Available Capacity is equal to the actual recorded capacity at the Main Meters at the Delivery Points. If the Plant is not fully despatched by the System Operator, then the GenCo is eligible to receive credit for its Declared Capacity, provided it is able to produce its Instructed Generation, plus or minus a margin for measurement error.

Under most PPAs between NBET and GenCos/IPPs, the generator is not penalized if capacity is unavailable due solely to fuel shortage outside of the control of the GenCo. Accordingly, the

availability of fuel to the generator must be tracked and a distinction is made for purposes of calculating Available Capacity depending on whether or not fuel is available.

4.3.2 As-is State

The MO is responsible for calculating the Available Capacity for each GenCo for determination of capacity charges. The MO uses the SO's Daily Operational Report to collect the data used for the calculation. We were informed that a single daily number – the peak generation - is taken from the Report and then averaged over the month to develop the billing determinant.

Actual generation at peak is used as the measure of availability for each day, i.e. the GenCo's capacity payment is determined based on the amount of energy the Plant produces during the peak hour, without considering other relevant measures including Declared Capacity, Instructed Generation, Tested Capacity and fuel availability. This approach to determining Available Capacity is erroneous and inconsistent with both MYTO and the PPA. On further investigation, we understand this approach was adopted by the MO to incentivize GenCos to produce as much as they can. It is no longer tenable going forward to TEM.

NIAF technical advisors have developed a Draft Operational Procedure for "Capacity Evaluation Procedure." The purposes of the procedure are: a) verify the validity of the declared generator capacity, and b) inform MO of the capacity for input into the settlement statement. The procedure describes the process whereby the SO shall verify the capacity of grid connected generation that has payments in its PPA that are dependent on its available capacity, and covers required data inputs, evaluation process, resolution of disputes and informing the MO of agreed capacity values. We understand that the procedure is being refined and finalized in coordination with the SO.

Furthermore, SO is empowered by the Grid Code to test plants for capacity; this function needs to be regularly performed during TEM.

SO practices for hourly tracking and communication of the data required for determination of available capacity are deficient in the following areas:

- Nominations are only relayed via telephone by some power stations – not all – to National Control Center/SO; such nominations are never firmed up in writing, contrary to Grid Code provisions;
- Only some IPP's nominate in writing;
- Some units go out on forced outages shortly after being nominated and tying to the grid – maybe for a few hours and at times the whole day – and the available capacity of such unit or the whole power plant is computed as the maximum out for such nomination period;
- In case of instructed reduction in production, such instruction ends up in the station's and NCC's entry logs and is not considered while aggregating monthly availability for settlement purposes;
- Nominations are never actually compared with aggregated unit/plant output at the end of the day;
- In the transmission substations the station operators are concerned with energy meter figures than with MW; same goes with distribution injection substations where some MW meters are either non-existent or defective;
- Capacities that pass through lines and feeders are not aggregated daily neither at the transmission substation nor distribution injection substations.

- Inadequate communication channels and defective communication habit between stakeholders.

4.3.3 Action Plan to Address Gaps

The following actions are required during the interim period prior to TEM:

- Training for MO and SO on the concept of Available Capacity and its calculation from operational data is required as a high priority. Such training can be integrated with training on the provisions of the Grid Code.
- SO should disseminate the Capacity Evaluation Procedure to the generators and conduct training on compliance requirements.
- New software and processes to track quantities and calculate Available Capacity from operational data, consistent with the definition of Available Capacity in MYTO and the PPAs, should be implemented. NBET has developed a spreadsheet model that does the calculation correctly. The SO/MO should implement this spreadsheet model immediately and provide the resources needed to support its continuous use.
- The MO/SO will require training on the use of the NBET spreadsheet for calculating Available Capacity.
- There should be scheduler's desk within NCC that is responsible for data collection and verification, in coordination with system operators and generators. SO can work with MO and NBET to develop the functions of the unit, staffing plan and job descriptions. NERC should provide for regulated recovery of the costs for this unit.
- The MO/SO should consider whether there is a need to supplement the Grid Code with a standalone manual on installed capacity requirements that clarifies the determination of Available Capacity, including GenCo operating and reporting requirements and capacity testing. As a practical matter, the initial version of such manual can be developed by a consultant, such as NIAF or the consultant that developed the spreadsheet for NBET, in recognition that the MO/SO currently lacks adequate qualifications in this area.

5 COMPLIANCE WITH GRID CODE REQUIREMENTS FOR SYSTEM OPERATIONS

5.1 Load Allocation to DisCos

5.1.1 TEM Requirement

Under the Vesting Contracts between NBET and the DisCos, each DisCo is contractually entitled to a percentage share of the total available generation. NBET (Seller) is required to make available to the DisCo (Buyer) the Disco Share Dependable Capacity and associated Gross Energy Output, and the DisCo agrees to accept and purchase same. NBET nominates the Disco Share Available Capacity for the action of the System Operator. The SO endeavours to meet the nominated quantities, and NBET cannot curtail or interrupt deliveries to the DisCo for economic or strategic reasons. NBET has the right to suspend delivery to the DisCo in the event of DisCo default.

It should be noted that, in practice, most likely the SO rather than NBET will implement the contractual provisions related to DisCo load allocation, as it is largely dependent on grid dynamics. The SO needs to have control of nominations and despatch.

The DisCo is responsible for provision of transmission services required to transmit its percentage share. The DisCo obtains transmission services from the GenCo Delivery Points to the DisCo Delivery Points at its own risk and expense including losses. This is accomplished by means of the transmission usage tariff, which is regulated by NERC, and the Grid Connection Agreement between DisCo and TCN.

5.1.2 As-is State

The generator nominations are aggregated by the System Controllers at NCC and despatched as loads to designated Area Control Centres (which, with the exemption of Port Harcourt Region, are 330kV substations within the Transmission Regions). The actual loading is according to predetermined percentages in accordance with current MYTO stipulations (i.e. the DisCo Share) of total generation with due consideration of transformation capacities of the substations and other dynamic exigencies of the grid, e.g. frequency and voltage stability. Operating the system to meet technical requirements is not always compatible with strict adherence to the DisCo share provisions. As a consequence, load allocation in accordance with share percentages in Vesting Contracts and as stipulated in MYTO is unlikely to happen now.

In the Area Control Centres (330kV Transmission substations), allocated load is despatched to 132kV substations for onward distribution to Disco load centres. The Disco load centres regularly violate their allocations. In some cases MW meters in outgoing feeders are either defective or inaccurate; there is also preponderance of grid indiscipline. Such violations are generally undocumented by the SO and are not officially communicated or tracked.

The load allocation schedule as sent out by NCC to the Area Control Centres currently does not get to the Disco. The Managing Directors/CEO's of Distribution companies claim they do not get copies of the daily load allocation document. This is the major reason they draw as much load as they can from the grid once power is available. Violations of load allocations are not sanctioned. This is a huge gap as, more so as Discos claim not to know what load to expect from the grid.

5.1.3 Action Plan to Address Gaps

- Allocated loads, in accordance with Vesting Contracts, should get to designated load points. Ancillary services in form of frequency and voltage support are essential ingredients that will make load allocation according to pre-determined percentages achievable. Adequacy of voltage support infrastructure available to the Transmission Services Provider on the grid is suspect. The grid should be operated in such a way that adequate spinning reserves are available at all times.
- There is need for a detailed grid network study to establish the level of voltage support requirement of the grid. TCN should thereafter put plans in place to procure and install them. While such efforts are on, however, SO/NCC should document all variations between actual allocations and Vesting Contract figures regularly and circulate to all stakeholders stating clearly the reasons for the variations.
- TCN/SO/NCC to demand reception of allocation schedule from Regional Control Centres (RCC's); RCC's should demand reception of allocation from 132kV substations and 132kV substations to demand reception of allocation from Disco load centers. These documentations should be circulated to all relevant stakeholders.
- SO/NCC should send the daily allocation to all Discos; demand evidence of reception and document. Allocations should also be published on the SO's website.
- SO should track and record instructed vis-à-vis uninstructed load drawn by DisCos. SO should promulgate a new operating procedure for such tracking and recording.
- All load allocation violations shall be documented by the SO and all relevant stakeholders duly informed. Sanctions should be in accordance with laid down procedures in the Grid Code and Market Rules.

5.2 SCADA, Measurement and Data Exchange

SCADA (supervisory control and data acquisition) is a type of industrial control system commonly used for power system operations. A SCADA system consists of the following subsystems:

- A human–machine interface is the apparatus or device which presents processed data to a human operator, and through this, the human operator monitors and controls the process.
- A supervisory computer system, gathering data on the process and sending commands to the process.
- Remote terminal units (RTUs) connecting to sensors in the process, converting sensor signals to digital data and sending digital data to the supervisory system.
- Programmable logic controller (PLCs) used as field devices because they are more economical, versatile, flexible, and configurable than special-purpose RTUs.
- Communication infrastructure connecting the supervisory system to the remote terminal units.
- Various process and analytical instrumentation

5.2.1 TEM Requirement

A fully functional SCADA EMS is highly desirable for TEM. When ready, SCADA will be useful for monitoring market transactions and compliance with SO instructions. However, SCADA is not essential for meter data collection, since meters can be read manually or by the AMR system and the readings transmitted verbally or electronically to the MO.

A fully functional EMS (Energy Management System) is necessary in order to operate a reliable transmission grid. SCADA is the building block for a good EMS but that is only the starting point. Besides accurately monitoring the transmission grid (2 to 10 second frequency), an EMS has a state estimator that calculates transmission flows and voltages and validates incoming meter data accuracy. This helps the system operators with "situational awareness" and helps avoid operating in regions of voltage and transient instability.

5.2.2 As-is State

SCADA is full of potential functionalities required for efficient management of an electricity power delivery grid. Siemens supplied, installed and commissioned SCADA facilities in all then existing legacy power stations and twenty-six (26) 330kV transmission substations. This is the first SCADA phase. The second phase of SCADA installation was facilitated by World Bank intervention and Siemens was engaged. This phase is an upgrade of the initial one, both in technology and spread. The project was delivered and actually functioned too, albeit sub optimally while the mandatory warrantee period was on. The SCADA second phase is monitoring 129 RTU instead of 25 that were in the first phase. All 330kV, 132kV and 33kV levels are included. A lot of communications equipments such as Power Line Carrier (PLC), SDH, and Radio have been integrated from the system to connect these signals to the various control centres. The System has thus been expanded more than 5 times and has become more complex to maintain; it therefore needs more expertise to manage and maintain.

Due to inadequate maintenance attention however, the facility gradually degenerated to the extent that only one of the three Area Control Centres (ACCs) was functioning before a management contract arrangement was entered into with Siemens and Telemit Consortium. This contract is on-going and the ACCs are now up and running.

It is noteworthy that the Consortium has been mandated and has agreed to restore the SCADA first phase (twenty-six 330kV substations and all legacy power stations) fully by the end of 2013, while the rest would be restored within the first half of 2014.

SCADA consists of the following facilities:

- The SCADA EMS system includes facility in 4 Control Centres, one National Control Centre and three Regional Control Centres. The equipment is manufactured, supplied, erected and commissioned by Siemens AG of Germany. Some of the communications facilities through which SCADA signals are transported are also from Siemens.
- The National Control Centre NCC in Osogbo is equipped with Sinaut Spectrum 4.4; while the Supplementary National Control Centre (SNCC) and Regional Control Center (RCC3), both in Shiroro, are equipped with Sinaut Spectrum 4.4.
- The Regional Control Centre in Benin (RCC2), is equipped with Sinaut Spectrum 4.4
- The Regional Control Centre in Lagos – Ikeja West - (RCC1) is equipped with Sinaut Spectrum 4.4.
- NCC Osogbo is equipped to supervise and monitor 26 330kV substations and some of the legacy power stations.
- SNCC is a backup for the NCC but also doubles as a Regional Control Center - RCC3. It supervises and monitors all 330kV substations, legacy power stations and about 40 132/33kV substations within its area of coverage.
- RCC2 in Benin is equipped to supervise and monitor 35 132/33kV substations under the Benin Regional Control.

- RCC1 Lagos is equipped to supervise and monitor 34 132/33kV substations under the Lagos Regional Control.
- NCC Osogbo has 7 substations connected via UHF radio, 9 substations connected via PDH equipment, 3 substations connected via SDH equipment (Siemens) – Jebba, Katampe 132kV and Shiroro – and all other substations connected via PLC equipment.
- SNCC / RCC3 Shiroro has 5 substations connected via UHF radio link, 4 substations connected via PDH equipment, 3 substations connected via SDH equipment (Katampe, Abuja Central Area and Shiroro) and all other substations connected via PLC equipment. RCC3 Shiroro is connected to the backbone for Multisite functionality through SDH equipment with a repeater station in Jebba transmission substation.
- RCC2 Benin has 9 substations connected via UHF radio link, 3 substations (Delta III, Delta IV and Sapele GS) connected via PDH equipment and all other substations connected via PLC equipment; RCC2 Benin is connected to the backbone for Multisite functionality through SDH equipment with a repeater in Akure transmission substation.
- RCC1 Lagos has 2 substations (Akangba and Ikeja West) connected via PDH equipment, and all other substations connected via UHF radio link equipment; RCC2 Benin is connected to the backbone for Multisite functionality through SDH equipment with a repeater station in Ayede transmission substation.
- The system includes a multisite configuration for the four control centres.

Regarding the status of RTU's and Communication Facilities, with the deteriorating state of the Control Centre due to lack of maintenance of the facilities therein and facilities in the remote stations, e.g. auxiliary power supplies to the RTU's and the grid communication equipments in the substation, it is not possible to get a clear picture of the state of on-going adaptation work. There is a need to send a team to each of the locations for a thorough check and analysis.

A deficiency list, which contains the problems that need to be solved in such stations, has since been compiled. While some of the problems are expected to be solved by Siemens, others are expected to be addressed by TCN engineers. Siemens has since solved all the problems they need to solve and are now waiting for TCN. It is suggested that the deficiency list be reviewed as some items may have gotten defective meanwhile. This will enable a complete status analysis.

Siemens AG is carrying out the Reactivation Project for the SCADA system for TCN. The first phase would be to reactivate all the 330 kV Stations (26) by December 2013, then reactivate all the 132kV. Currently all the 4 Control Centres are up and running and 22 out of the 26 Transmission Stations are online.

The following additional information on SCADA is provided in the following appendices:

- Appendix 5 provides List of substations: adaptation and RTU Status.
- Appendix 6 provides 330/132KV and generating stations RTU status as of 14/10/2013.

5.2.3 Action Plan to Address Gaps

- Considering the size of the Network, it is recommended that all NIPP substations and generating stations be integrated into the SCADA base. The same goes for all new 330kV and 132kV transmission stations too. This will enhance a clear picture of the Generation and Transmission Network.
- TCN should put more effort in the maintenance of the existing infrastructure.

- There is a gap in the skill level of the System Operators as far as utilization of existing SCADA is concerned. It would be desirable to have a core SCADA engineer on the Operators' shift.

- Training of Operations and Maintenance Teams should be embarked upon without further delay. Meanwhile a two-year Maintenance Contract should be in place until TCN staff are ready for the handover. During the contract period, hands-on training would be provided to the Teams.

5.3 Submission of Scheduling and Despatch Data and Contract Nominations

5.3.1 TEM Requirement

Part 6 of the Market Rules contains detailed instructions regarding submission of scheduling and despatch data and contract nominations. Each non-hydro generator submits a Day-ahead Nomination showing (a) Quantity Nomination; and (b) Price Offer. During the Transitional Stage, each hydro generator submits its Quantity Nomination, but does not include a Price Offer in the Day Ahead Nomination.

A Price Offer made by a thermal generator consist of: (i) one each of a "Hot Start Price", a "Warm Start Price" and a "Cold Start Price"; (ii) up to three (3) monotonically increasing Energy Prices in N/MWh expressed as a function of MW output over the range of capacity, that is, minimum to maximum output; (iii) the Break Points, that is the MW levels between which a given Energy Price applies; and (iv) a No-Load Price in N/hour, being the hourly fixed price required to run the Generating Group. It should be noted that these Price Offer requirements shown in the Market Rules are not necessarily consistent with the pricing terms in the PPAs, and may need to be modified.

Each Generator must submit its Nomination in accordance with the format prescribed by the SO. The System Operator must: (a) record the receipt of a Nomination, indicating the time that the Notification was received by the System Operator; and (b) confirm receipt of Nomination to the Generator that submitted same within thirty minutes of receipt of a Nomination. The SO verifies the proper content, format and syntax of any Nomination submitted by a Generator.

5.3.2 As-is State

As stated earlier, as part of normal daily operations, Declared Capacity is supposed to be sent by the GenCo to NCC and recorded in despatch logs. The present mode is that plants nominate their "available" units with their full capabilities. Nomination is done via GSM telephone and thereafter entered into both the station's and NCC's log books; rarely are nominations received in writing from the power stations. At present, there is no requirement for submission of Price Offers.

5.3.3 Action Plan to Address Gaps

Elsewhere in this report, we have recommended the formation of a working group consisting of SO, MO, NBET and representatives of GenCos and IPPs. The following activities related to submission of scheduling and despatch data and contract nominations should be added to the mandate of the working group:

- Develop formats, data entry templates and associated instructions manual for the Daily Nominations to be submitted by generators.

- Formalize the procedures to be used by generators for submission of Daily Nominations, with reference to draft procedures being developed by NIAF consultants.

- If advisable, provide a website portal accessible to the generators where they can enter their Nominations directly into a database that is then used by the SO for daily operations and by the MO for collecting data used for settlement.
- Formalize the procedure for SO confirmation of receipt of Nomination to the Generator. One advantage of a website portal is that the data can be checked and receipts generated automatically by the system. However, if the SO chooses not to automate the process, then another mechanism should be developed and communicated to the generators.
- Conduct training on the requirements in the Market Rules for submission of scheduling and despatch data and contract nominations, and the new operating procedures that will be rolled out prior to TEM.

5.4 GenCo/IPP Provision of Ancillary Services

5.4.1 TEM Requirements

Ancillary Services include spinning reserve/frequency control, voltage support and black start. During TEM, operations planning should henceforth include computation of daily ancillary services requirement. Furthermore, until SCADA is fully available, efficient documentation processes should be put in place to accurately report instructed deployment of ancillary services.

Characteristics of each unit within a generating plant should be attached as schedule to the Connection Agreement. This has not been done in all the plants and it is a necessity towards an Ancillary Services Agreement. Each unit normally should also contribute some minimum level of such services to the grid. When more is required, then the MO/NBET pays.

Along with day-ahead nominations, generating plant operators are expected to also declare their ancillary service availability.

Operations Planning at NCC/SO are expected to compute on daily basis, taking into consideration all grid contingencies, what is required in form of ancillary services. This is shared among GenCos that have declared ancillary services available. Proper tracking should thereafter be embarked upon by both the supplier and NCC/SO for proper settlement by MO/NBET.

5.4.2 As-is State

By rule of thumb, the amount of power produced by the largest generating unit on bars is nominally what should be kept as spinning reserve. In our case Egbin units are the largest – 220MW each. This is the minimum amount of spinning reserve the system needs and is what should be spread among plants that have offered to supply such ancillary service. Only Kainji offers some limited reserves that is grossly inadequate, while Delta is the only plant offering black start. The black start facility in Delta has recently been showing signs of fatigue and may eventually give up.

Most of the time however, the system runs without any spinning reserve at all. Daily tentative generation schedule for 19.10.2013 shown in Appendix 7 is a typical example.

5.4.3 Gaps for Initiation of TEM

- The gap here is substantial and other power plants have to be encouraged to join in the provision of such services too.
- It is obvious that 220MW is not enough as spinning reserve in our network, taking into consideration so many other factors. Therefore, as many generators as are tied in should be asked to keep some minimal reserves, which will take care of perturbations occasioned by feeder tripping.

- Apart from frequency stability, voltage stability is a major issue. All reactors and capacitor banks in the transmission network should be checked for adequacy and against possible defects.
- Schedules attached to Ancillary Services Agreement between TCN and GenCos are not complete. Efforts should be made to complete them.

5.4.4 Action Plan to Address Gaps

- It is general knowledge that Shiroro is equipped with the facility to provide voltage support. Such services are very essential now, going forward. Shiroro is the nearest generating station to places like Kano, Gombe, Maiduguri and Yola. The distances are huge and voltage levels in such locations are below standard. Shiroro should therefore be urged to commission this facility.
- Some loads connected to both the 132kV and 33kV networks introduce harmonics, thereby significantly distorting the load factor, leading sometimes to voltage collapses. Thorough study of such loads should be immediately commissioned to determine compliance to provisions of the Grid Code.
- SO/NCC should have a record of all such load plants and track the load characteristics.
- Claims by individual plant, especially as far as voltage support is concerned, should be verified. Sapele claims to have black start capability; this claim should be verified by the SO/TCN before such Agreement can come into operation.
- Operations planning should henceforth include computation of daily ancillary services requirement. Furthermore, until SCADA is fully available, efficient documentation processes should be put in place to accurately report instructed deployment of ancillary services.

6 COMPLIANCE WITH MARKET RULES FOR MARKET SETTLEMENT SYSTEMS AND PROCEDURES

6.1 Contract Register

6.1.1 TEM Requirement

According to the Market Rules:

- "20.3.1 The Market Operator shall establish and maintain a Contract Register in which it will keep contract information disclosed to it by Participants pursuant to this Rule 20.320.3 for the purpose of:
  - (a) keeping a record of generation capacity and contracted quantities in order to evaluate generation adequacy; and
  - (b) assisting the Commission in evaluating the load covered by contracts entered into by each Distributor.
- 20.3.2 The Contract Register shall not contain any price or other commercially sensitive information.
- 20.3.3 The Contract Register shall document the power contracted from each Generator and bought by each Participant …"

The MO needs information about the terms of the contracts regarding the calculation of the billing determinants for the Settlement Statements. The MO needs to know the contracted capacity amounts in the PPAs and the mechanism or formula for calculating the contracted energy and Available Capacity as specified in the PPAs. The Market Operator uses the contract information submitted by Participants and recorded in the Contract Register to calculate the quantities bought and sold by each Participant under the contract.

6.1.2 As-is State

At present, the MO does not have the Contract Register. The MO has access to the PPAs between PHCN and IPPs, but does not have access to the PPAs and Vesting Contracts between NBET and the Successor Companies, which are not yet executed between the parties. The MO has not attempted to harmonize the current logic for calculation of settlement quantities for the GenCos with the formulae for calculating the contracted energy and Available Capacity as specified in the PPAs. The SO may not be cognizant of operating requirements contained in the PPAs.

As pointed out earlier, the method currently used by the MO for calculating capacity payments to Successor GenCos is not consistent with the formulae in the PPAs. NBET has developed a spreadsheet to calculate the Available Capacity billing determinant, but MO/SO have yet to adopt this spreadsheet as the basis for tracking capacity and determining the settlement quantities.

6.1.3 Action Plan to Address Gaps

We suggest that the most expeditious approach to address the gap in the MO's compliance with the Contract Register provisions of the Market Rules is as follows:

- NBET should prepare the Contract Register in a form that provides clear instruction to MO regarding calculation of settlement quantities. The Contract Register should also provide

clear instruction to the SO to the extent that the SO must take into account the terms of the contracts during routine system operations.

- MO and NBET should establish a working group to harmonize the logic used by the MO to calculate settlement quantities with the formulae in the contracts.

6.2 Process Used for Determination of Settlement Quantities

Settlement Quantities are the processed data resulting from application of the validation and correction processes to meter data obtained from a meter in respect of each participant. Calculation of the Settlement Quantities is part of the Settlement process

6.2.1 TEM Requirements (as per the Market Rules)

The processes required for the determination of the Settlement Quantities for the initiation of the Transition Electricity Market are as follows:

- All energy calculations for settlement in the market shall be measured through a commercial metering system, which measures the physical flows.
- The Market Operator (MO) shall check the manual readings received from the Participants against those received from the System Operator (SO). If the readings differ, the MO shall request the SO to read again for proper reconciliation. The SO's reading shall have precedence and be deemed valid.
- On collection of meter data, the Market Operator shall organize, validate and where necessary correct the data received from the participant, in order to establish the metered quantities applicable to each participant for the settlement process. The process of data organization, validation and correction may be manual or automatic through the AMR System.
- To calculate the Settlement Quantities, the readings from the participant's commercial metering system, shall be adjusted by the Market Operator to take into account losses where applicable, in accordance with the principles established in the Market Procedure.
- Collated reading shall be checked for consistency by verifying that incomer energy reading is equal to the sum of the readings in the outgoing feeders (TPs for the Distributors) in the transmission station within the check tolerance. In such cases, unless the meter is identified as faulty, through a test, the higher of the two values shall be considered valid and shall be used in the market settlement process to calculate the settlement quantities.

6.2.2 Actual Process in use for the Determination of Settlement Quantities (As-is State)

- Energy calculations for settlement in the market are measured through commercial metering systems.
- The Market Operator (MO) compares the manual readings received from the Participants against those received from the System Operator (SO). If the readings differ, the SO's readings take precedence over the participant's readings and are deemed valid for use in the calculation of the Settlement Quantities.
- On collection of meter data, the Market Operator organizes, validates and where necessary corrects the data received from the participants, in order to establish the metered quantities applicable to each participant for the settlement process. At the moment, the MO employs the manual method in the organization, validation and correction of the data pending the commissioning of the AMR System.

- Apart from adjustments of the readings from the participants' commercial metering system, for Transmission Losses using the TLF, the MO does not take into account the other losses in the system, in the calculation of the Settlement Quantities. An example of the adjustment for other losses is the adjustments for losses due to location of the Participant's Trading Point meters outside the Connection Points.

- The MO checks the Collated readings for consistency by verifying that incomer energy reading is not lower than the sum of the readings in the outgoing feeders (TPs for the Distributors) or higher by more than 2%, as stipulated in the Market Procedure. In any case where the variation is outside the check tolerance, the higher of the two values is usually considered valid and used in the market settlement process.

6.2.3 Gaps to be addressed for the initiation of TEM

Apart from the Transmission Losses, the MO does not take into account the other losses in the system in the calculation of the Settlement Quantities. For example, the Inter-Disco boundary meters are installed at locations other than the exact boundaries between the Discos, and the best that is currently done is the sharing of the energy readings between the affected Discos.

6.2.4 Action Plan to Remediate the Gap

The framework for the adjustment of the readings for the possible losses due the installation of the commercial meters at locations different from the connection points or the exact boundary points, should be developed, to enable the MO apply the adjustments in the calculation of the Settlement Quantities.

6.3 Process for Settlement Statements

The Settlement Statement is one of the reports (outputs) of the Settlement System, which consists of data bases, processes, hardware and software. The Market Operator (MO) is responsible for the development and maintenance of the Settlement Software and data of the Settlement System. He is also responsible for the administration of the System. Appendix 8 shows the logic flow of the Settlement System.

6.3.1 TEM Requirements for the Settlement Statements

In line with the Market Rules, the requirements on the Settlement Statements applicable for the Transition Electricity Market (TEM), are as follows:

- The MO shall be responsible for the preparation of the monthly Settlement Statements for the Electricity Market.

- The Settlement Statement shall calculate the monthly net results for each participant, in view of:
  - Payments to be received due to energy sales
  - Payments to be received due to sales of ancillary services
  - Minus payments due to energy purchases
  - Minus payments due to charges for services received
  - Plus or minus corrections to previous Settlements

- In each month, the MO shall prepare two Settlement Statements, namely, the preliminary Settlement Statement and the Final Settlement Statement.

- Not later than ten business days after the beginning of each month, the MO shall prepare and send the Preliminary Settlement Statement (PSS) to each Participant through electronic mail. The Preliminary Settlement Statement shall include:
  - The TLF in each participant's connection points
  - The quantities (Energy & Capacity) bought and sold by the participants
  - The Transmission wheeling charges due from the Participants
  - The MO and SO administrative charges
  - The payment or charge for market transaction for the month
  - Sufficient supporting data to enable each participant to verify the settlement calculations
- Not later than twenty (20) business days after the beginning of each month, the MO shall send to each participant the Final Settlement Statement (FSS), which shall contain the same information as contained in the Preliminary Settlement Statement, but adjusted to rectify any errors or discrepancies observed in the PSS.
- At any time within Sixty (60) days after receiving the FSS, a participant may notify the MO of any complaint or dispute relating to the content, concerning either:
  - The quantities, or
  - The settlement amount in respect of market transactions, transmission usage charges, and System Operation and Market Operation administrative charges
- When the MO determines that a FSS has to be corrected, the MO shall send a written notification to the affected participants/or service provider, with the corresponding explanations.
- The MO shall include the related corrections as a "correction item" in the Settlement Statement corresponding to the first Market Settlement Process following the resolution of the complaint or identification of any error by the MO.

6.3.2 The Settlement Statement As-is State

The MO is responsible for the preparation of the monthly Settlement Statements for the Nigerian Electricity Market. The Settlement Statement calculates the monthly net results for each participant, in view of:

- Payments to be received due to energy sales
- Payments to be received due to sales of ancillary services
- Minus payments due to energy purchases
- Minus payments due to charges for services received
- Plus or minus corrections to previous Settlements

Every month, the MO prepares two Settlement Statements, namely, the preliminary Settlement Statement and the Final Settlement Statement. In line with the Settlement Calendar, the MO prepares and sends the PSS to each participant, through the E-mail and courier, not later than ten business days after the beginning of each month.

Not later than twenty (20) business days after the beginning of each month, the MO sends to each participant the Final Settlement Statement (FSS), which contain the same information as contained

in the Preliminary Settlement Statement, but adjusted to rectify any errors or discrepancies observed in the PSS.

Some of the times, the participants notify the MO of some complaint or disagreement, concerning either:

- The quantities, or
- The settlement amount in respect of market transactions, transmission usage charges, and System Operation and Market Operation administrative charges

The MO takes up some of the corrections at times, but in most cases does not. The process of complaint or dispute resolutions on the settlement statements, as provided in the MR, is yet to be implemented

The Final Settlement Statement is treated as an invoice to the Purchasers and credit note to the Sellers. That is beyond the FSS, no invoices are given.

At present, the Settlement Statement is generated using an Excel spreadsheet approach. The Settlement Software is in the final development stage but not yet operational. The Settlement Software is developed and supported by an outside consultant. A set of the typical Final Settlement Statements for the month of July 2013 is attached as Appendix 9.

6.3.3 Gaps to be Addressed in the Settlement Statement for TEM Initiation

- The MO Settlement Software is not yet fully implemented.
- The process of making complaints in respect of the quantities used for settlement calculations or the results of settlement calculations regarding amounts for market transactions and charges for services received by the participants/service providers is not in line with the Market Rules. Also the process of resolving such complaints (when any is made) by the MO is not according the Rules or procedure.

6.3.4 Action Plans to Remediate the Gap

- The MO should expedite the process of transitioning to the use of the new Settlement Software, and provide adequate training to staff on the use of the software.
- The participant's rights and obligations as well as the MO's rights and obligations, in the electricity market, as provided in the Market Rules should be enforced by the Commission so that the settlement Calendar should be applied in both the complaints and resolutions. The Commission should ensure this is achieved before TEM is declared.
- The process of making complaints in respect of the quantities used for settlement calculations or the results of settlement calculations regarding amounts for market transactions and charges for services received by the participants/service providers needs to be aligned with the Market Rules.
- The process of resolving such complaints by the MO needs to be aligned with rules and procedures.
- NERC needs to operationalize its procedures related to market disputes.
- MO and NBET need to coordinate regarding NBET role in dispute resolution.

6.4 Settlement System Architecture, including Interoperability and Security

6.4.1 TEM Requirement

The settlement system architecture is not specified in the market rules and procedures. However, it is clear that the MO should use best industry practices for the development, implementation and testing of the settlement system.

6.4.2 As-is State

The MO has developed a software application to handle the settlement processing and treasury roles of the MO's functions. The application is based on the client-server model. All client workstations will be required to have the client software installed.

The backend database application consists of the Interbase data base application. The current MO processing flow is listed below. Please see Appendix 3 –Fig. 4 Market Operator Process flow.

Step 1: System Operator Daily and monthly Operational Report is obtained from System Operator via Email. DisCo sends monthly trading Point meter reading via email system

Step 2: The AMR system obtains monthly readings from the EDMI and ITRON meters on the field. The monthly readings are transmitted to central AMR system the MO office.

Step 3: The AMR readings are compared with the meter data records submitted by the DisCo. Both meter records are compared, validated and reconciled.

Step 4: The database is updated and the preliminary statement is generated.

Step 5: The preliminary statement is sent through the MO approval process. If approved, the statement is sent to respective stakeholders else, it is returned for comparison and reconciliation.

Step 6: The preliminary settlement statement is sent to respective stakeholders for validation of the statement.

Step 7: A 2-day window is provided for the respective stakeholders to review the statement and send complaints to the MO if any. If complaints are received, dispute procedure is initiated

Step 8: The Final settlement statement, Credit notes and invoices are prepared and sent through the MO approval process.

Step 9: Once approved, the final settlement statement, credit notes and invoices are despatched to the all parties including the respective DisCo nominated Bank. Credit notes are sent to GenCos while Invoices are sent to DisCos. MO, TCN, CHQ also get their credit invoices.

Step 10: Payments are received from the various DisCos. Payment from the DisCos are received into a DisCo nominated Bank account with joint standing mandate by the MO and the corresponding DisCo regarding payment disbursement formulas and procedures

Step 11: The payments due from the DisCos are then confirmed with the Banks involved in the transactions.

Step 12: After confirmation of payments by DisCo, Payments are made by the MO to the respective stakeholders via a pre-authorized jointly (MO and corresponding DisCo) mandated standing order with the bank.

Step 13: This marks the end of the business monthly billing cycle. Please refer to Appendix 3 Fig. 5 – Typical Market Operator monthly business processing cycle.

The MO operates an internet web portal www.onem.gov.ng. The web portal is active but has not been officially commissioned and deployed in production. Upon audit of the portal, some modules and links are not functional on the web portal. The existing web portal has the following characteristics:

- The web portal is hosted on the public internet with a known and reputable web hosting company.
- Each direct stakeholder is expected to access only the data required for his use.
- Direct stakeholders (System Operator engineers) shall be required to submit periodic trading point meter readings
- All data entry shall be periodical downloaded into the Market Operator Settlement Software system.
- The web portal uses an Open Source RDMS (Relational Database Management System) - MySql database application.
- The proposed data submittal by System Operator engineers via the online web portal is stored as "structured data". This data can now be readily analysed, processed and archived. This enables new data processing functionality such as market business data forecasting, trends analysis and Business Intelligence capabilities otherwise not previously available.

6.4.3 Gaps for Initiation of TEM

- Processes are manual with little or no levels of automation observed. This makes the system prone to user errors, abuse and malicious use.
- Communications between the SO and other Stakeholders regarding energy readings are largely via the use of email and telephone communication. This is extremely insecure, prone to risks related to Social engineering, user omissions, errors, malicious use of data, abuse of data etc. Note: This data forms the criteria and basis on which payments to stakeholders are made. All payments processes originate from this data.
- Records are largely stored in paper logs, folders and archives. Documents and data collected are stored as "unstructured data". The data is not auditable and cannot be effectively analysed, processed or archived.
- Data from the AMR system has to be physically copied over to the ONEM Enterprise settlement software. Physical copy of data via flash drives and other removable media are vulnerable to data corruption, "chain of custody" issues, unauthorized manipulation of data by users and malware, lack of data confidentiality and privacy etc, and thus constitutes a huge systemic risk to the system.
- Treasury process including payment calculations and disbursement are performed via the use of Microsoft Excel spreadsheets. Data in the spreadsheets exist as unstructured data. This is inadequate as entries or modifications cannot be effected audited and secured. Data from several spreadsheets cannot be readily analyzed and queried. Capabilities such as trend analysis, historical perspective on data, Business Intelligence, data reporting etc. are either ineffective, inefficient or unavailable.

Regarding Information and Communications Technology (ICT):

- There is no evidence of an ICT corporate governance structure and thus there is insufficient internal control processes to protect the meter data records and other critical data from data repudiation, malicious use from unauthorized users, data loss, abuse etc.
- Server and data infrastructure hosted by various departments are distributed and located in each separate department location which increases the probability and risk of data loss, abuse of data, malicious use from unauthorized users, data repudiation etc.
- Access to data and system resources are generally un-auditable and unsecured
- Access to critical areas such as server room, AMR room and Treasury where confidential and critical data are stored is not securely restricted and auditable.
- The existing email system is currently outsourced and thus will be difficult to implement e-discovery processes as required by the market rules Section 47.1.3.
- There is no evidence of an Electronic Document Management System (EDMS) or other alternative to enable document archival compliance with market rules Section 47.1.3. Storing documents is hardcopy paper format is not sufficient for compliance as paper print media degrades over time among other constraints.

Regarding Settlement Software:

- The settlement software application is based on the client-server model. All client workstations will be required to have the client software installed. This introduces several administrative constraints such updating the client software when patches and hot fixes are released.
- The application security depends on embedded application-level security controls. This increases the administrative cost required to maintain the system security. Server Operating System security if violated will compromise the backend data.
- High Availability features are currently unavailable in the software application platform
- Software application lacks strong user controls to prevent hacking attacks such brute force attack, dictionary attacks etc.
- The Customer Relationship Management (CRM) interface in the application is inadequate and need to be improved.
- Reporting modules are inflexible and need significant efforts (including software developer's input) to customize if required.
- The data conversion module of the AMR data to the Market Operator settlement software is proprietary and untested

Regarding MO ONEM Web portal:

- Non-confidential and confidential information are published on the same web server and hosted on the internet public
- On the web portal, direct Electricity Market stakeholders (System Operator, Market operator, Distribution Companies, Generation Companies, NBET, NERC etc) access to critical data is restricted by use of pre-assigned and pre-authorized user name and password restriction.
- User security controls are insufficient

- There is significant risk is user repudiation as a result of using only one-factor authentication process for logging onto the confidential sections of the web portal. This comprises data integrity. If a user's password is compromised, an unauthorized user may gain access to the confidential data and thus violate data integrity.

6.4.4 Action Plan to Address Gaps

- We recommend that the backend database application of the Market Operator settlement software application be upgraded from the InterBase database application to a leading Commercial Relational Database Management System (RDBMS) application.

- As described on the original Equipment Manufacturer's website "InterBase is a full-featured, high performance and scalable relational database for software developers who are looking to embed a low cost, zero-admin, lightweight database into applications on Android, iOS, Windows, OS X, Linux and Solaris".

- There is no evidence that the InterBase database application supports the following enterprise features which increases data security and enterprise-level data integration support:
    - Native Network Layer encryption
    - Enterprise directory capability (e.g. Active Directory, Kerberos, etc)
    - Role Based Access Control (RBAC)
    - Open Database Connectivity and Java Database Connectivity software drivers etc.
    - SQL clustering, Mirroring, synchronous replication etc

- Integration with the database by other applications may be limited unlike leading commercial database applications.

- We recommend that Market Operator settlement software be configured as a two-tier application platform (at the minimum). Physically and logically separating the backend database from the application server front-end significantly reduces the risk of single point of failure

- We recommend the implementation of a Lightweight Directory Access Protocol (LDAP) authentication interface to the proposed Enterprise Directory service. This ensures that Market Operator no longer relies on application-level security controls to restrict access to the application and data.

- We recommend server and application-level cluster implementation to enable High Availability and Graceful Degradation. This ensures that the application remains functional and available in the event that components of the system fails or become unavailable. Note: The Market Operator Settlement software application when commissioned and deployed shall be required to be highly available to prevent disruptions in the Market Operator's monthly business cycles.

- We highly recommend a direct data interchange between the AMR server and the Market Operator Settlement software application. Manually and physically copying AMR meter data across from the AMR server to the Market Operator Settlement software application introduces immense risk of user error, data corruption, omission, unauthorized manipulation of data by unauthorized users and malware, data repudiation, lack of data confidentiality and privacy etc

- We recommend that the 'proprietary' data conversion module of the AMR meter report data (designed and created by the Market operator's settlement software application

developer) for the Market Operator settlement software be further reviewed, tested, independently certified and approved for use. Non-compliance with this recommendation shall expose the Market Operator to stakeholder claims, dispute and possible fines from the regulatory authorities.

- We also recommend complete functionality and stress (performance) testing of the Market Operator's settlement software application (including all modules and features) by an independent software testing lab or entity prior to use. This will provide the required levels of Quality Assurance to the related stakeholders and Market participants.
- We recommend the immediate cessation of critical business data submission between the System Operator, DisCos, stakeholders and Market Operator via email or telephone communication. All energy data reporting from the System Operator shall be distributed to stakeholders by hosting on a private built-for-purpose web portal owned and operated by the System Operator.
- Similarly, all Market Operator related data reporting and communication shall be distributed to stakeholders by hosting on a private built-for-purpose web portal owned and operated by the Market Operator.
- Data partitioning by respective data owners is critical for data management, ownership, auditing, accountability and regulatory compliance purposes
- The proposed web portals shall be located on a private network (not hosted on the public network) and ONLY pre-authorized users and stakeholders shall have access to the web portal. All other users access shall be denied. Note: This data is confidential and relates to Nigeria's national Critical Infrastructure.
- Access to the proposed secure web portals for submitting and accessing confidential information shall be integrated with a multifactor authentication server platform. Users shall be provisioned and pre-assigned with a user token device generating one Time Passwords (OTP) which shall ensure non-repudiation of data.
- Submitting business data via the proposed secure web portal significantly reduces the risk of data repudiation, omission, and unauthorized manipulation of data, disputes and penalties by the corresponding regulating authorities. Section 32.5 of the Market rules also states that "The Market Operator shall safeguard any Settlement information that is Confidential Information."
- In addition, the collection and processing of submitted data in "structured data" format presents new capabilities for real-time processing, Business Intelligence, data mining, data reporting, data archiving to the MO in compliance with Section 47.1.3. of the Market Rules etc.
- We recommend that the MO settlement software application be web-enabled to increase availability, functionality, security, performance and flexibility. This is not a Condition Precedent for TEM however; this is a supporting recommendation for the Condition Precedents to TEM.
- As a matter of urgency, we urge the MO management to begin the process of initiating processes and procedures establish required levels of Internal control processes required to secure all data obtained and processed by the MO.
- We recommend the centralization of server resources across the various departments. Access to these resources should be authenticated against an enterprise directory service. This ensures that data access to these resources are authenticated, audited and secure

- We recommend that all data obtained, received, processed and ultimately stored be compliant with Section 47.1.3. of the Market Rules.
- We recommended (at the minimum protection level) that the server room be relocated to a special fit-for-purpose room in a restricted part of the building. Casual human traffic (walking or strolling) along the corridors in this location should be highly controlled and restricted. Use of biometric-access control devices complemented by the use of Video Surveillance camera and recording equipment shall constitute the minimum level of site and server room protection.
- We recommend the immediate creation of an ICT policy and standards document to cover ICT operations across the enterprise network. Such documents shall include User Acceptable Use policy, End-point security policy, server security policy, data retention policy to include the various categories of data types, Recovery Point Objective (RPO), Recovery Time Objectives (RTO) etc. This will aid in setting the basic requirement on how to manage and secure all data obtained, processed and stored in the course of the business processing cycle.
- We recommend training workshops be organized for participants and stakeholder that will be accessing the extranet, internet web portal for effective usage and increased stakeholder adoption of the web portals.

7 MO PAYMENTS ARRANGEMENTS FOR MARKET TRANSACTIONS

7.1 Collections from DisCos and Payments to GenCos

7.1.1 TEM Requirement

The payment arrangements for TEM are set out by the Market Rules. The Market Rules provide that NBET will be responsible for handling energy and capacity payments for its contractual obligations to GenCos and IPPs. The MO will be responsible for handling payments for all other services providers.

The following outlines the respective steps in the payment procedure:

- MO provides settlement statement for all market participants, i.e. NBET, GenCos, DisCos, NERC and services providers.
- Market Participants vet MO settlement statements and NBET invoices DisCos to pay for generation services provided by GenCos and IPPs. MO invoices DisCos for all other services.
- MO and NBET maintain separate Trading Accounts to receive payments from DisCos and make payments to GenCos and services providers.
- MO and/or NBET also may have bank accounts to hold other funds required to operate the market, such as line of credit, FGN allocation, DisCo three month guarantees to NBET etc.

During TEM, DisCo nonpayment will not be tolerated, as DisCos are expected to use their own sources of revenue and credit to meet their contractual payment obligations to MO and NBET. Late payments from DisCos should attract a penalty and surplus attract interest.

The DisCo payments timeline, as provided by the Market Rules and the Vesting Contracts, is as follows:

- MO issues preliminary Settlement Statements 10 business days after the end of the month
- Market Participants have 5 business days to review the Settlement Statements and raise objections
- MO has 5 business days to address/resolve contested Settlement Statement before issue of Final Settlement Statement (FSS).
- This brings to 20 business days within which the MO Settlement Statement issue and resolution is completed.
- DisCos have 10 days after the 20 business days window for finalizing the Settlement Statement to make payments
- This means DisCos are contractually obligated to make full payments on their invoices 37 days after the end of the months of invoice (or 10 days after receipt of FSS/NBET invoice).

DisCos have the obligation to provide the Market Operator and NBET with Security Cover for their liabilities arising from the Market Settlement process for payment that may be due to services provided and energy bought. The DisCo is supposed to provide the Market Operator the proposed Security Cover upon registration as a Market Participant. The DisCo is supposed to provide NBET

the proposed Security Cover, equal to three months of generation charges, upon execution of the Vesting Contract.

7.1.2 As-is State

The Settlement Statement issued by the MO constitutes the market invoices to the DisCos for the revenues accruable to the GenCos, the Transmission Service provider, the System Operator and other service providers in the market. However, at present, these invoices are not used as the basis for actual payment obligations. Instead, the MO uses a completely separate procedure to determine the amounts that must be paid to each entity. This separate procedure is in place because the DisCos' collections are inadequate by a wide margin to meet the revenue requirements shown in the Settlement Statements. For example, for the June 2013 billing period, which was settled from July 20th to August 15th 2013, a total sum of N24 billion was invoiced to the Distributors while the sum of N11.3b was received from the Distributors and paid to the different beneficiaries in the market.

The rules governing the determination of actual payment requirements were developed internal to PHCN and are not presently regulated. The rules are referred to as the cash flow waterfall. The following bullets provide a high level summary of the rules for the waterfall:

The first tier of the waterfall consists of the minimum revenue required by each entity (DisCos, GenCos and Services Providers) for essential operating costs, including salaries and an allowance for other operating costs. PHCN's estimates are not based on MYTO cost figures, as PHCN has its own estimates of the minimum monthly Naira amount that each company must receive at the bare minimum.

The second tier of the waterfall is payment of fuel expenses. We were informed that since mid-2012, tiers 1 and 2 have been 100% funded each month by the revenue collected from the DisCos.

The third tier of the waterfall is payment owed to IPPs under their PPAs. Within this tier, some IPPs are prioritized higher than others. In recent years, PHCN has been partially defaulting on payments to IPPs. The accumulated liabilities are being transferred to NELMCO at present.

Further tiers presumably would involve proportionate payment of the remaining unmet revenue requirements of the Market Participants. However, at present collections are not sufficient to make such payments.

The MO and each DisCo maintain a joint escrow account(s) at a Nigerian bank to manage the waterfall transaction. The DisCo is supposed to deposit all of its collections into the escrow account. The bank is then instructed to disburse the funds in the account either to the DisCo's own imprest bank account or the MO's own bank account, which is called the PHCN Market Clearing Account. The instruction is issued in the form of a standing joint mandate that is signed by both the ED MO and the CEO of the DisCo. The bank then disburses all of the funds accumulated in the escrow account for the month either to the Market Operator or to the DisCo.

The joint mandate standing instruction describes the minimum percentage payment of the monthly settlement statement and schedule of payment to the MO (into a designated PHCN clearing account). Stakeholders including GenCos, TSP, SO, MO, NERC are all paid their corresponding pro-rated minimum percentage payment based on the revenue received from the corresponding DisCo.

According to the standing order instructions, the bank is to disburse funds in the following sequential order (refer to Appendix 3 – Fig 5 – Typical Market Operator monthly business processing cycle):

1. On the 20th day of every month, transfer a percentage of the Market Operator's monthly Settlement invoice amount in respect of electricity supplied to the DisCo to the PHCN Market Clearing Account. The fixed percentage varies by DisCo and was developed by the MO over time in light of historic DisCo collections performance.

2. At the completion of 1, fund the imprest account(s) of the DisCo to cover payroll and other essential operating expenses.

3. After the funding in 2, on the last working day of the month, transfer the remaining percentage of market invoice (or part thereof if the fund available is less) to the PHCN Market Clearing Account.

4. At the completion of 3, transfer the balance if any to the DisCo imprest account(s).

These bank transactions are subject to periodic audits by PHCN Internal Audit Department. Such audits are conducted as frequently as every three months, but this is not a formalized business practice. The MO does not have the capacity to monitor on an ongoing basis the transactions occurring in the joint escrow accounts with the DisCos according to the standing orders. There is no process in place to audit a DisCo's remittance of its collections to the joint escrow accounts.

At the completion of the waterfall process, the entities have incurred nonpayments consisting of the difference between the revenue requirements amounts shown in the Settlement Statements and the amounts actually paid by the DisCos according to the standing orders. There is no expectation that nonpayments accrued to date will ever be recovered. Accordingly, the MO does not formally track nonpayments using best accounting practices.

Moving forward, NERC is developing new rules governing the cash flow waterfall for the allowable revenue accruable to market participants, service providers and the Regulator during the interim period between declaration of Interim Period and initiation of the Transitional Electricity Market. The existing banking arrangements between the MO and the DisCos, as described above, are expected to remain in place for the interim period. There is an expectation that nonpayments accrued during the interim period will be recoverable by the market participants during TEM. Accordingly, the MO must institute a suitable accounting system to formally track such nonpayments.

Figure 7-1 shows the payment timeline used by the Market Operator. The current payment timeline used by the MO complies with the Market Rules for TEM.

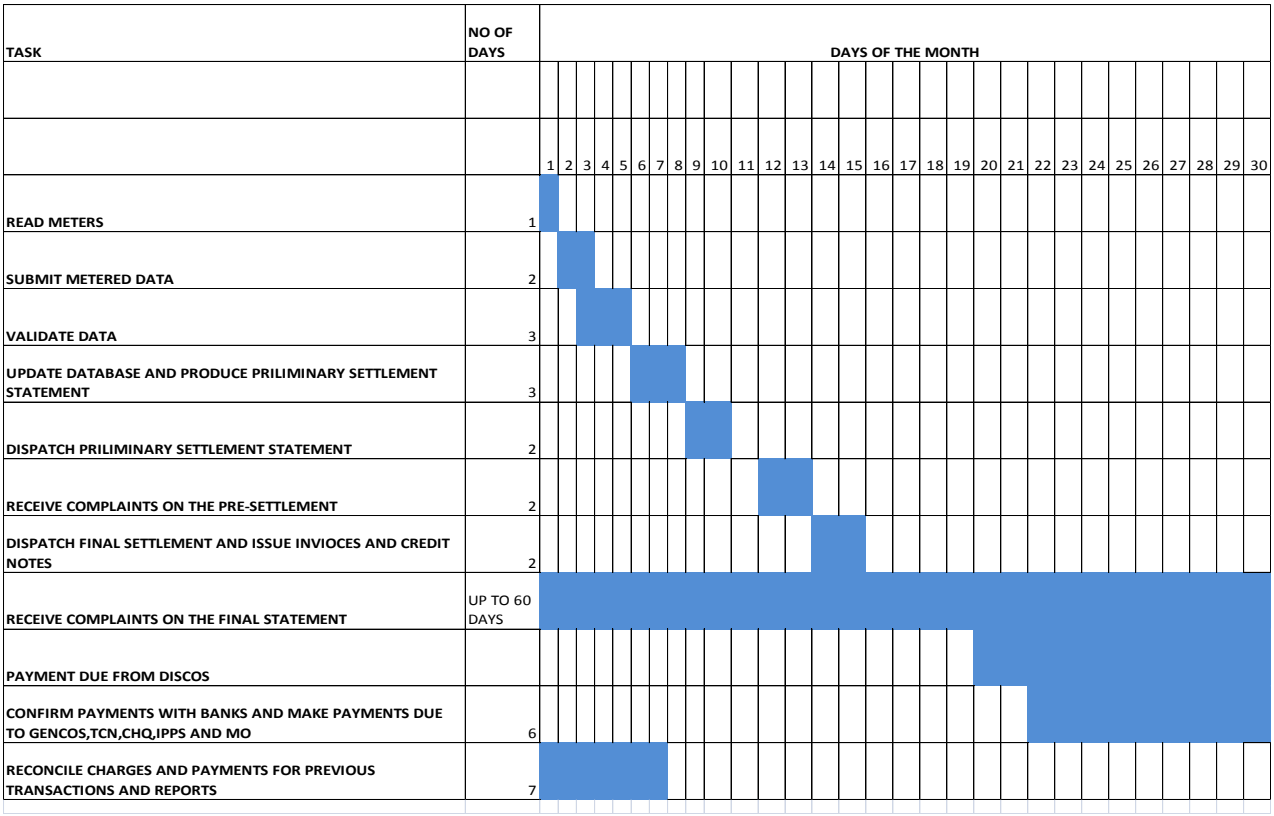


Figure 7-1: Payment Timeline Used by Market Operator

The payments process has a provision for processing complaints on the market invoices. Our impression is that at present there is a low volume of complaints, because the Successor Companies are together under the Holding Company and differences can be handled administratively from within the Company. At the onset of TEM most likely there will be a high volume of complaints by the GenCos and DisCos about the Settlement Statement, such as regarding GenCo capacity charges. High complaint volume is something the MO has not experienced to date. The MO is planning to integrate the filing of complaints within the market participant portal of the MO website. However, this portal is not yet operational.

None of the DisCos have posted the required Security Covers to MO and NBET for their liabilities arising from the Market Settlement process.

The MO has produced a manual on "Procedures for Admission and Participation during the Transitional Market." The Market Procedures Manual lays out the requirements for application and registration, security cover, metering, meter data collection and procedures and calendar for the settlement process.

7.1.3 Action Plan to Address Gaps for Initiation of TEM

The systems, procedures and payment timeline used by the MO to receive payments from DisCos are already largely compliant with the Market Rules for TEM, except that DisCos are not required to remit the full amounts shown in the Settlement Statements. When TEM is initiated, DisCos will be obligated to pay the full amounts shown in the MO invoices. The DisCos will make payments directly to the MO's Market Clearing Account.

The following gaps need be addressed prior to TEM:

- DisCos should be required to provide adequate security cover that the MO can draw upon in the event of DisCo nonpayment, such as the security deposit arrangement set up for

NBET. To our knowledge, none of the new owners have complied with this requirement. NERC should order the DisCos to post their security cover as soon as practical during the Interim Period prior to TEM.

- We understand that once the Interim Period is declared, DisCos will be responsible for making full payments on the settlement amounts as developed using the cash flow waterfall for the Interim Period. However, if nonpayment risks cannot be adequately addressed during the Interim Period, NERC should consider requiring some or all DisCos to continue to deposit their entire collections into a joint escrow account with MO/NBET, similar to the current arrangement between MO and DisCos.

- The MO should form a working group with representatives of DisCos and NBET to harmonize new banking arrangements for TEM and develop appropriate arrangements to replace or revise the current system of joint escrow accounts and standing orders used by MO and DisCos.

- NBET is planning to conduct an EOI for entities who want to provide payments agent services to NBET. One of the purposes of the EOI is to solicit ideas from the financial community on how the payments arrangements should work, including roles and responsibilities of the payments agent vis-à-vis NBET. This EOI may shed light on the optimal structure for the MO's own banking arrangements. It is advisable for the MO to monitor and participate to the extent possible in this EOI so as to glean lessons learned that may be applicable to the MO's operations.

- MO will need to institute suitable methodology and arrangements for accounting and billing the DisCos for payment arrears, and paying the service providers for past due amounts.

- It is highly advisable that the MO create a customer interface on the MO website to facilitate administrative matters such as filing of complaints regarding Settlement Statements. We were informed that such complaint portal is under development. However, as of now there is no interface on the MO website for Market Participants to make submissions.

- The MO manual on Procedures for Admission and Participation during the Transitional Market can be enhanced by presenting full description of the calculation of the charges for each service. The manual should also cover the calculation and administration of interest and penalties, if any, on late and nonpayment.

- There are currently no payments flowing from DisCos to NBET. NBET and the DisCos will need to implement appropriate systems and procedures for such payments.

- It should be noted that there is a lingering concern that during the Interim Period prior to TEM and in the early going of TEM, despite the provision for security cover, DisCo nonpayment may create instability in the payments waterfall. The problem will be most acute for a DisCo that finds that MYTO II rates are so far below Cost Based Rates that despite its best efforts it cannot cover its expenses and raise necessary capital for a sustained period prior to NERC's revision of the rates. This would undercut the energy reform process. This potential problem is beyond the scope of the current report, except to note that NERC should take the lead in developing backstop solutions in consultation with Market Participants and FGN.

7.2 Market Operator Accounts

7.2.1 TEM Requirement

As stated under section 31.22 of the Market Rules, "The Market Operator will hold and operate the following separate trust accounts:

- Market Operator clearing account
- Market Operator reserve account
- Market operator surplus account
- And any other such accounts that the MO may wish to establish

7.2.2 As-is State

During our audit exercise, we were only informed of the existence of joint escrow accounts with DisCos and an active Market Operator clearing account into which disbursements from the joint escrow accounts are deposited and from which payments the services providers are initiated.

Due to MO privacy reasons, we are currently unable to verify that separate ledger were created and maintained for the following accounts:

- Imbalance Energy;
- Ancillary Services;
- Reliability Must-run Services;
- System Operation and Market Administration Charge;
- Penalties for Participant's non-compliance with the
  - provisions of these Rules;
  - credit costs and Default Interest in accordance with Rule 35.635.6;
- Default Interest in accordance with Rule 38.1138.11;
- Cost of Imbalance Energy; and
- Other amounts included in an Invoice issued by the Market Operator in accordance with this Part.

7.2.3 Action Plan to Address Gaps

We recommend randomly scheduled third-party independent audit of the MO operated accounts to provide greater transparency and reduce the financial risk of the Electricity Market.

7.3 MO Accounting Systems for Billing and Payments

7.3.1 TEM Requirement

The MO will need to maintain an adequate accounting system for tracking billing and payments. It may be possible at the onset of TEM to track transactions using a spreadsheet financial accounting model, but ideally the MO should implement commercial accounting software for tracking transactions, as the amount of payment transactions will be voluminous. The MO's financial accounting system should integrate with the MO's settlement software and statements provided by the banks that serve as payment agents, ideally through use of seamless data interfaces. A robust accounting system will provide a non repudiable audit trail for market transactions.

7.3.2 As-is State

The present system of accounting for market transactions relies on the use of Excel spreadsheets to record the monthly payments waterfall process. As pointed out earlier, the MO does not have the capacity to monitor bank transactions that occur in its joint escrow accounts with the DisCos.

Since, at present, there is no expectation that the MO will recover nonpayments accrued to date, the MO does not bother with detailed tracking of payments and nonpayments using standard accounting practices. However, at the end of the month the MO is able to provide a summary of the market invoice amounts and the payment amounts.

The MO's settlement system fails to integrate with either the MO's own finance accounting system or a payment agent's system.

7.3.3 Action Plan to Address Gaps

- MO will need to maintain adequate accounting records for amounts past due to the various service providers due to DisCo late- or non-payment during TEM, and provide for the calculation of association interest and penalties.
- MO should work with the banks to develop a real-time integration interface with the bank account reporting portals, so that the MO can effectively track payments received from the DisCo and disbursed to the service providers. In general, MO needs to maintain its own record of every payment and disbursement transaction in the market.
- We suspect that the current reliance on the use of spreadsheets by the MO accounting unit is inadequate and unsustainable for TEM. The MO should form a project team to make recommendations on software systems, processes, organization and staffing for tracking and accounting for transactions in the market. The team should also make recommendations on how to best integrate the market transaction tracking and accounting system with the settlement system.
- NERC should determine allowable interest rates and penalties associated with late- and non-payment amounts.

8 NBET PROCESSES AND SYSTEMS FOR TEM

8.1 Settlement Process

The proposed settlement process being developed by NBET is as follows:

Step 1: System Operator Daily and monthly Operational Report is obtained from System Operator via Email. DisCo sends monthly trading Point meter reading via email system

Step 2: The AMR system obtains monthly readings from the EDMI and ITRON meters on the field. The monthly readings are transmitted to central AMR system the MO office.

Step 3: The AMR readings are compared with the meter data records submitted by the DisCo. Both meter records are compared, validated and reconciled.

Step 4: The database is updated and the preliminary statement is generated.

Step 5: The preliminary statement is sent through the MO approval process. If approved, the statement is sent to respective stakeholders else, it is returned for comparison and reconciliation.

Step 6: The preliminary settlement statement is sent to respective stakeholders for validation of the statement.

Step 7: A 5-day window is provided for the respective stakeholders to review the statement and send complaints to the MO if any. If complaints are received, dispute procedure is initiated

Step 8: The Final settlement statement, Credit notes and invoices are prepared and sent through the MO approval process.

Step 9: Once approved, the final settlement statement, credit notes and invoices are despatched to the all parties including the respective DisCo nominated Bank. Credit notes are sent to GenCos while Invoices are sent to DisCos. MO, TCN, CHQ also get their credit invoices.

Step 10: GenCo issues invoice to NBET. NBET Power Procurement and Contracts reviews and sends to Finance.

Step 11: PPPC review Final Settlement Statement and generate Disco invoice and send to Finance. Finance receives reviewed and generated DisCo invoice and may seek clarification if necessary

Step 12: Review and send DisCo invoice to Finance

Step 13: NBET issues DisCo invoice

These are the interim payment process in place. Since NBET will not be making payment during interim period, the final payment system that will be procured will incorporate this interim payment into what will be used.

Step 14: DisCo makes payment via the Payment Agent, and GenCo receives payment via the Payment Agent.

8.1.1 Gaps for Initiation of TEM

We are informed that NBET currently has the capability to perform the above process using spreadsheet applications and manual processes. This is not auditable, secure or efficient.

There is a gap in coordination between NBET and the MO on integration of the separate settlement processes, software, interfaces, roles and responsibilities that each entity will manage. NBET is currently proceeding with planning and developing its own systems with little input from MO, and vice versa.

8.1.2 Action Plan to Address Gaps

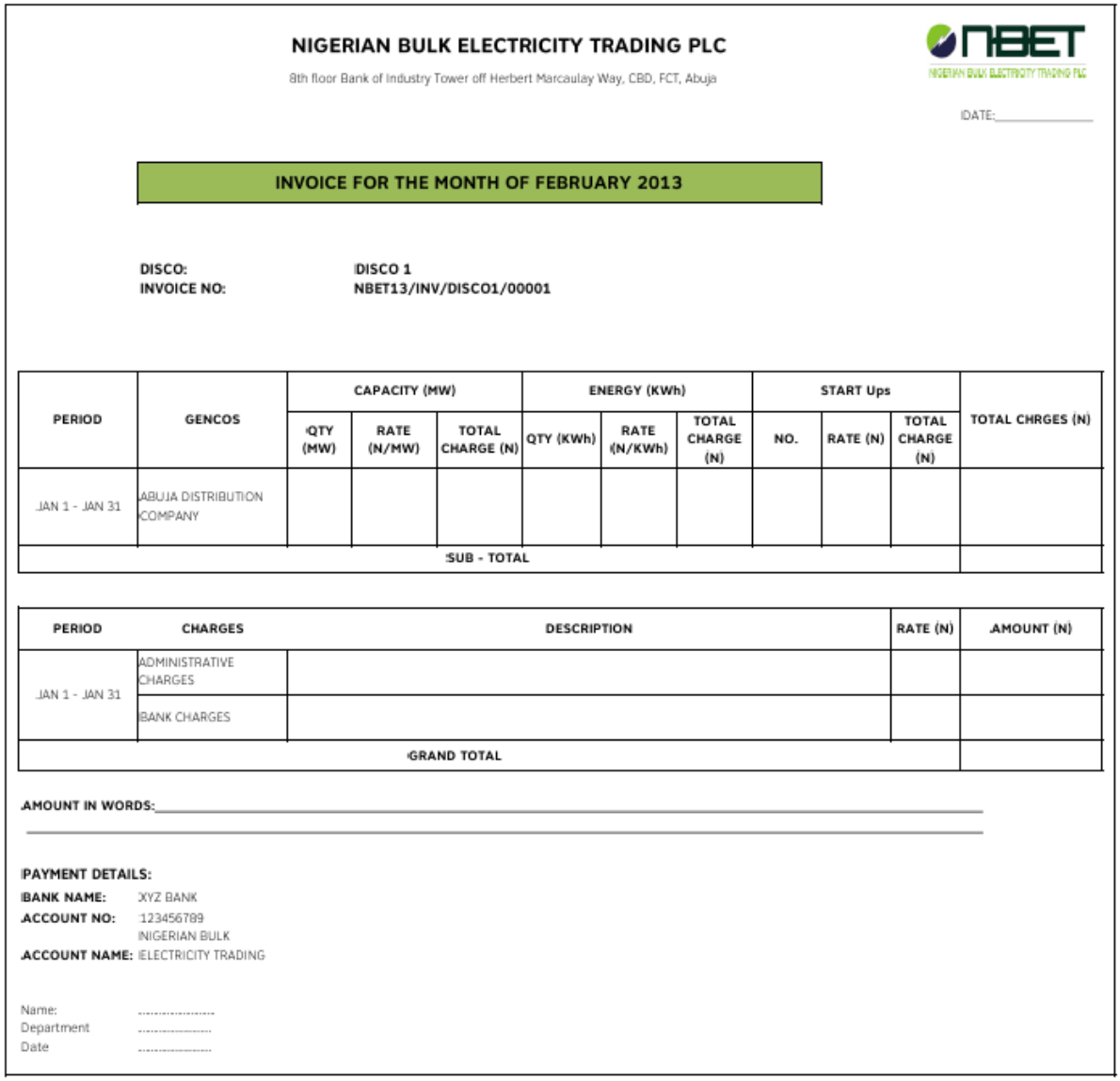
- The arrangements required to implement and automate, as far as possible, the NBET settlement system are being developed and/or in the process of procurement, as informed by NBET. Such arrangements should be tested during the Interim Period.
- There is a need for stronger coordination between NBET and the MO during the lead up to TEM on settlement processes, software, interfaces, roles and responsibilities that each entity will manage.
- A regular schedule of meetings between the two parties, e.g. biweekly, may facilitate joint project planning and adherence to the schedule for TEM.

8.2 Invoicing

8.2.1 TEM Requirement

NBET's role during TEM is to buy power from the GenCos and IPPs under bilateral PPAs, and sell the collective generation quantities to the DisCos. To carry out this role according to the requirements in the contracts and the Market Rules, NBET will need to institute the following invoicing arrangements:

- Review/Reconciliation of GenCo and IPP Invoices – NBET vets the invoices received from its generation suppliers with reference to the contract quantities shown in the MO's settlement statements, and the pricing terms in the PPAs.
- Submission of Invoices to DisCos – The MO advises NBET on the contract quantities for generation sales to the DisCos, and NBET prepares and submits invoices to the DisCos. NBET develops the charges shown in the invoices so as to recover the full amount owed to the GenCos, per the PPA obligations. The current form of the NBET invoice to DisCos is shown in Figure 8-1.



NIGERIAN BULK ELECTRICITY TRADING PLC

8th floor Bank of Industry Tower off Herbert Marcaulay Way, CBD, FCT, Abuja

DATE:_____

INVOICE FOR THE MONTH OF FEBRUARY 2013

DISCO: DISCO 1
INVOICE NO: NBET13/INV/DISCO1/00001

PERIOD	GENCOS	CAPACITY (MW)			ENERGY (KWh)			START Ups			TOTAL CHRGES (N)
		QTY (MW)	RATE (N/MW)	TOTAL CHARGE (N)	QTY (KWh)	RATE (N/KWh)	TOTAL CHARGE (N)	NO.	RATE (N)	TOTAL CHARGE (N)	
JAN 1 - JAN 31	ABUJA DISTRIBUTION COMPANY										
SUB - TOTAL											

PERIOD	CHARGES	DESCRIPTION	RATE (N)	AMOUNT (N)
JAN 1 - JAN 31	ADMINISTRATIVE CHARGES			
	BANK CHARGES			
GRAND TOTAL				

AMOUNT IN WORDS:_____

PAYMENT DETAILS:
BANK NAME: XYZ BANK
ACCOUNT NO: 123456789
ACCOUNT NAME: NIGERIAN BULK ELECTRICITY TRADING

Name: .....
Department .....
Date .....

Figure 8-1: NBET Invoice to DisCo

8.2.2 As-is State

- Review/Reconciliation of GenCo and IPP Invoices – The IPPs submit invoices to the Market Operator as a normal business practice. However, the Successor Company GenCos have not yet adopted the practice of submitting monthly invoices, since there is no expectation that such invoices would be used for actual payment purposes, as described earlier. IPP invoices are currently verified by the MO for payment purposes. NBET is not involved.
- Submission of Invoices to DisCos – As per earlier discussion, all market invoices are currently handled by the MO. NBET is not involved.

8.2.3 Action Plan to Address Gaps

Elsewhere in this report, we have recommended the formation of a working group consisting of SO/MO, NBET and Market Participants. The following activities related to invoicing should be added to the mandate of the working group:

- The Successor Company GenCos should adopt the practice of submitting monthly invoices to MO/NBET. The PPA has samples of expected GenCo's invoice to NBET. The invoice format is largely a product of agreed terms in the PPA.

- During our investigations, we found that the MO and NBET have not yet reached a common understanding of institutional responsibilities for market invoices, among other issues. MO, NBET and NERC need to work out the framework for allocating roles and responsibilities. MO and NBET should work together to design and implement critical interfaces for data exchange related to market invoices.

- SO and NBET should work together to develop the framework for NBET to monitor contract quantities despatched by SO and ensure that operations are consistent with terms and conditions of the PPAs.

8.3 Payments Arrangements

8.3.1 TEM Requirement

Under TEM, NBET is responsible for payments to GenCos/IPPs, and the MO makes payments to all other services providers and NERC. NBET can make payments to the GenCos and IPPs directly, using its own banking arrangements, or elect to retain the MO as its payments agent if agreed by the GenCos/IPPs.

The roles and responsibilities of MO vis-à-vis NBET for settlements, market invoices and payments during the Interim Period and during TEM will need to be agreed between the MO, NBET and NERC. The PPAs specify that NBET (Buyer) pays the GenCo/IPP (Seller). The Market Rules are consistent with the provisions of NBET's contract, i.e. NBET is allowed to make payments to GenCos and IPPs. The Market Rules also allow for the MO to continue making the payments to the GenCos and IPPs, using contract prices as the basis for settlements, if agreed with NBET and the GenCos/IPPs.

Assuming NBET will handle payments to generators during TEM, NBET will need to institute new procedures, arrangements, roles and responsibilities to operationalize a payments system consisting of receipt of payments from DisCos and MO, and disbursements to GenCos and IPPs, including access to the various securitization arrangements that are being put in place to assure NBET's financial security. NBET's payments arrangements must be carefully integrated with those of the MO, since both parties collect from the same DisCos.

For the Interim Period prior to initiation of TEM, NBET is proposing the following payment procedures, which fully comply with the Market Rules for TEM:

- MO provides settlement statement to all market participants, i.e. NBET, GenCos, DisCos, NERC, etc.

- NBET Power Procurement/Contract Management vets settlement statements and invoices DisCos to pay for energy consumed plus capacity payments.

- NBET maintains Trading Accounts to receive payments from DisCos and make payments to GenCos.

- NBET's accounts also hold FGN allocation and other working capital funds for draw down to meet short term payment shortfalls.

- NBET's payment merit order and proportion formula to govern payment priorities has been developed and is pending approved by the NBET Board.

8.3.2 As-is State

As we are informed, NBET has its trading account in place but is yet to use it for the purpose of trading because the MO is still in charge of payment in the market.

We are also informed of procurement efforts by NBET to select an authorized payment agent to directly handle and oversee receipts from DisCos and payments to GenCos and DisCos. The firm KPMG has been retained to develop a payments agent solicitation consisting of first an EOI and followed by and RFP. The EOI is being used to gather input and ideas from the financial community that may prove useful for designing the final form RFP. The EOI stage is completed. Vendors have been selected and will soon be sent the RFP that is at the final stage of completion. NBET expects that the payment agent selection and implementation of the new payment system will be completed during the first two months of 2014.

It is expected that MO will continue in its current role as the entity responsible for settlements, market invoices and payments during the Interim Period such time as TEM is declared, NBET's contracts are effective and NBET's payment agent arrangements are in place.

8.3.3 Action Plan to Address Gaps

MO, NBET and NERC should make a joint proposal on the transitioning of payments responsibilities and functions from MO to NBET. The working group should also come up with a proposal for how to integrate MO and NBET systems for these functions.

We think there is a possibility that DisCo nonpayment could persist into the early stages of TEM. NERC should take the lead to develop suitable arrangements in lieu of a payments waterfall that will provide adequate financial security for NBET and MO in the event of DisCo nonpayment during TEM.

8.4 Accounting System for Billing and Payments

8.4.1 TEM Requirement

When NBET takes over from the MO the responsibility for billing, collections and payments of amounts due from DisCos and amounts payable to GenCos, it will need to maintain an adequate accounting system for tracking and managing transactions and payment obligations. Ideally NBET, or its payment agent, should implement commercial accounting software for tracking transactions, as the amount of payment transactions will be voluminous. NBET's financial accounting system should integrate with the MO's settlement software and statements provided by the banks that serve as payment agents, ideally through use of seamless data interfaces. A robust accounting system will provide a non repudiable audit trail for market transactions.

8.4.2 As-is State

As stated earlier, payment arrangements are currently managed by the MO. NBET is currently not managing the billing and payment for the stakeholders, nor has NBET implemented an accounting software for market transactions, or decided the role of the proposed Payments Agent in accounting for market transactions.

8.4.3 Action Plan for TEM

NBET or its designated agent needs to develop and implement an accounting system to record and manage market transactions drawing on best utility practices used by market operators. The system should integrate with NBET's invoicing system and with bank transaction accounting records.

8.5 IT and Telecommunications for Settlement System

8.5.1 TEM Requirement

The settlement system architecture is not specified in the market rules and procedures. However, it is clear that NBET should use best industry practices for the development, implementation and testing of its settlement system.

8.5.2 As-is State

NBET currently receives monthly energy, capacity reading and settlement statements from the MO. NBET processes the payment data using a customized spreadsheet for calculating payments, as distinct from the Settlement Software that the MO has developed. NBET also uses the data to build data models for business operations and eventually payment to stakeholders.

Business critical communication with stakeholders is via email and telephone communication. Refer to Appendix 3 Fig 6 – NBET process flow.

8.5.3 Gaps for Initiation of TEM

- Data interfaces between NBET and MO/SO are yet to be developed.
- Communications between the SO, MO and other Stakeholders regarding energy readings are largely via the use of email and telephone communication. This is extremely insecure, prone to risks related to Social engineering, user omissions, errors, malicious use of data, abuse of data etc.
- Records are largely stored in paper logs, folders and archives. Documents and data collected are stored as "unstructured data". The data is not auditable and cannot be effectively analysed, processed or archived
- Treasury process including payment calculations and disbursement are performed via the use of Microsoft Excel spreadsheets. Data in the spreadsheets exist as unstructured data. This is inadequate as entries or modifications cannot be effectively audited and secured. Data from several spreadsheets cannot be collectively analyzed and queried. Capabilities such as trend spotting and analysis, historical perspective on data, Business Intelligence, data reporting etc. are unavailable, ineffective and inefficient
- There is no evidence of an adequate ICT infrastructure required of an entity the scale and importance of the NBET's role in the market.
- The server room does not meet the minimum industry standard requirements as it is void of functionality such a purpose-built fire-suppression, redundant cooling, redundant electrical circuits, audited access to the server room, etc.
- Data is currently being stored on user workstations and laptops as there is no evidence of a converged data infrastructure. There is significant risk of critical data loss, data repudiation, unrecoverable data corruption, etc if a laptop is lost or stolen.
- NBET is in the final stage of selecting a vendor for its Enterprise Business Solution (EBS), which should help to address the identified vulnerabilities.
- There is no evidence of a Disaster Recovery, Business Continuity Plan or High Availability infrastructure to ensure that the monthly business cycle of the NBET is not disrupted in the event of an unplanned component or systemic outage such as strikes, civil unrest, hardware/network failure etc.

- There is no evidence of a suitable end-point security policy or solution to ensure the security of stored data.
- Enterprise security is loose and needs to be urgently addressed

8.5.4 Action Plan to Address Gaps

- NBET and the MO should continue to work together during the lead up to TEM to harmonize the two settlement systems, to gain lessons learned in the development of the MO's Settlement Software, to provide for efficient data interfaces between NBET and MO/SO, etc.
- We urgently urge the creation of an ICT corporate governing structure to ensure that urgent and critical ICT requirements to support the operations of the NBET are identified and implemented. Such requirements shall include the security and availability of business data and computing resources etc
- We recommend the immediate cessation of critical business data submission, instructions and data communication between the NBET, System Operator and Market Operator, banks other related stakeholders via email or telephone communication.
- All data reporting and business communication from the NBET to stakeholders shall be distributed by posting the data on a private built-for-purpose web portal owned and operated by the NBET.
- NBET may obtain contract quantity data from the MO/SO via the private built-for-purpose web portal owned and operated by TCN. NBET may also implement a data interchange or integration interface with the MO/SO's extranet portals to enable the automatic and secure data exchange between entities. However, the recommended data interface is not a Condition Precedent for TEM.
- The proposed NBET web portal shall be located on a private network (not hosted on the public network) and ONLY pre-authorized users and stakeholders shall have access to the web portal. All other users access shall be denied. This data is confidential and relates to Nigeria's National Critical Infrastructure.
- Access to the proposed secure web portal for submitting and accessing confidential information shall be integrated with a multifactor authentication server platform. Users shall be provisioned and pre-assigned with a user token device generating one Time Passwords (OTP) which shall ensure non-repudiation of data.
- Distributing business data via the proposed secure web portal significantly reduces the risk of data repudiation, omission, and unauthorized manipulation of data, disputes and penalties by the corresponding regulating authorities. In addition, the collection and processing of submitted data in "structured data" format presents new capabilities for real-time processing, Business Intelligence, data mining, data reporting, data archiving etc to the NBET in compliance with Section 47.1.3. of the Market Rules.
- We recommend the creation of a highly detailed Business Continuity plan to cover all critical data and telecommunicating processing components. A required Condition Subsequent of the Business Continuity plan shall be the establishment of a remote Business Continuity Center (BCC). This shall ensure that in the unlikely event of the production datacenter site or service unavailability; data processing shall continue and not disrupt the business processing cycle of the NBET. The type of Business Continuity Centre ("hot", "warm" or "cold") shall depend on the NBET's Risk Assessment and Business Impact Analysis evaluation.

- We recommend that hosted e-discovery services be procured as part of the hosted email service contract. This ensures that all incoming and outgoing emails are archived and available for retrieval in the event of the discovery process in civil litigation matters
- We are informed that the NBET is procuring an Enterprise Resource Program (ERP) application that will manage the NBET payment and invoice process (including other NBET functions). Financial bids have been opened.
- We have also requested a Business Analysis and Technical Implementation design / plan that is the basis of the proposed ERP implementation but we informed that this is being compiled by the NBET. As a result of this, we are unable to evaluate the proposed IT settlement software of the NBET for suitability, security, scalability, etc.
- We recommend the inclusion of the relevant stakeholders such as NERC or qualified representatives in the development of the NBET Business Analysis and Technical Implementation design/plan. This will ensure final implementation meets all the required compliance objectives of the regulatory entity.
- We recommend that NERC constitute a technical working committee to interface in reviewing the proposed data models used by the NBET, SO and MO to ensure the homogeneity of reports, assessments and other related market-related information.

9 NBET CONTRACTS AND COMMERCIAL ARRANGEMENTS

Rule 6.3.1 of the Market Rules requires all electricity trading arrangements during the transitional Stage to be consummated through contracts.

Based on this Rule and in preparation for the Transitional Electricity Market, NBET executed Power Purchase Agreements (PPA) with the successor generation companies of PHCN on February 21, 2013. It also executed Vesting Contracts on the same date with successor electricity distribution companies.

9.1 GenCo Power Purchase Agreement

9.1.1 TEM Requirement

The PPAs must be fully in effect as a condition of TEM.

9.1.2 As-is State and Gaps for Initiation of TEM

Although NBET has executed the PPAs with the GenCos, the contracts are not yet effective. Each PPA is expressed to become effective on the "Effective Date" (which is defined as the date of signing) and to remain valid for the Term (20 years from Share Purchase Close).

The use of the terms, "Effective Date", "Share Purchase Close" and "Term" in the PPA creates some confusion as to the actual date the PPA is intended to become legally effective and binding. Going by the definition of Effective Date, the PPA would have become effective since February 21, 2013 when the PPA was signed. However, the PPA will only be required to be valid during the Term, which only commences on the achievement of the Share Purchase Close. Share Purchase Close is defined as the date on which "the management and control of Seller is handed over to successful bidder under the Share Sale Agreement and Shareholders Agreement". This condition now has been met, but the PPA will be effective only when TEM is declared.

The management and control of the Seller under each PPA was handed over to the successful bidders and purchasers on November 1, 2013. Thus by now, the PPA ought to have become "effective" or valid". However, NERC is in the process of developing Interim Rules, which will suspend the effectiveness of the PPAs till March 01, 2014.

Furthermore, the PPA also provides conditions precedent for the obligations of the parties, non-satisfaction (without a waiver) of which will still affect the effectiveness of the PPA as the affected party would not be under any obligations thereunder.

NBET's conditions precedents are that:

(a) NBET has executed full and effective Vesting Contracts with the Distribution Companies. Although NBET executed the Vesting Contracts since February 21, 2013, the contracts are yet to become effective.

(b) National Council on Privatization (NCP) has issued a Transfer Order that has come into effect directing that any extant or accruing unpaid liabilities of the Buyer arising from obligations under this Agreement, shall be automatically transferred in full to the Nigerian Electricity Liability Management Company Limited (NELMCO). This condition has been met. NCP has issued the order.

From the foregoing, the conditions precedent for the obligations of NBET under the PPA are still to be satisfied or waived. Therefore the PPA is yet to become fully effective.

The following PPA Schedules are still outstanding, and NBET expects to complete then prior to TEM.

SCHEDULE 6 – Insurance Coverages

- Commercial/General Liability: Coverage amount is yet to be provided.
- Workers Compensation and Employers Liability: Coverage amount is yet to be provided
- Construction and Erection All Risk Insurance: Coverage amount is yet to be provided
- Cargo Insurance: Coverage amount is yet to be provided.

SCHEDULE 11 - Rehabilitation Schedule

- Required to be provided by the Seller

SCHEDULE 12 - Maintenance Schedule

- Maintenance Outage Schedule to be provided by Seller to Buyer and the System Operator yearly, in line with the Grid Code.

ANNEX A - Industry Documents

- To specify the industry documents that are to be referenced by the agreement and those to which the plant must adhere regarding safe and prudent operation.

ANNEX C - Certificate for Conditions Precedent

- Copy to be included by both parties

ANNEX D - Certificate for the Plant

- Copy to be included by the seller

ANNEX E - Certificate for the Connecting Transmission Line

- Copy to be included by the seller

ANNEX F - Certificate for the Connecting Gas Pipeline

- Copy to be included by the seller

9.1.3 Action Plan to Address Gaps

It is expected that NBET will populate all the schedules under the PPA before the commencement of TEM.

9.2 Novation of PHCN PPAs to NBET

9.2.1 TEM Requirement

PHCN's PPAs must be novated to NBET as a condition of TEM. As stated above the Interim Rules now suspend the initiation of TEM to March 01, 2014. Although the Interim Rules anticipate that the novation of the existing PPAs from PHCN to NBET would have been concluded before TEM, it

provides that if the novation occurs during the Interim Period, "while the IPP provides the invoices, the associated payment responsibilities will remain with the Market Operator while any shortfalls shall be addressed in line with Rule 19(a) above." Thus, the novation is not expected to be fully operational before TEM.

9.2.2 As-is State

None of the existing PPAs with AES, AGIP or Shell has been novated to NBET.

9.2.3 Action Plan to Address Gaps

NBET is still discussing with PHCN on the novation of these PPAs. NBET has also begun independent discussions with AES and Shell on this subject. Negotiations for the novations is progressing well and NBET is confident of concluding all the novations before the winding-up of PHCN or the commencement of TEM, whichever is earlier.

9.3 DisCo Vesting Contract

9.3.1 TEM Requirement

The Vesting Contracts must be fully effective as a condition of TEM.

9.3.2 As-is State and Gaps for Initiation of TEM

Although NBET has executed the Vesting Contracts with the DisCos, the contracts are not yet effective. The Vesting Contract is required to commence on the Effective Date, which itself is defined as a date after the Execution Date (February 21, 2013), which NCP, by an order, stipulates that the contract shall become effective. Clause 4.1.1 expressly makes this order by NCP as condition precedent to the effectiveness of the Vesting Contracts. No such order has been made by NCP.

Other conditions precedent that must be satisfied or waived on or before the Effective Date are:

(a) the Parties must have registered as Market Participants and obtained all material Authorisations for the discharge of their respective obligations under this Contract. In fulfillment of this condition, NBET has registered as Market Participant and has since obtained a license from NERC as a trading licensee.

(b) NBET has entered into PPA, and such PPA must be in full force and effect. In satisfaction of this condition, NBET has executed several PPAs. However, as mentioned above, none has become legally effective.

(c) The DisCo has put in place security cover to the reasonable satisfaction of NBET. None of the Distribution Companies has provided this cover as of the time of this report.

The following Vesting Contract Schedules are still outstanding:

SCHEDULE 4 – Energy and Capacity Payments

- This schedule is required to be subsequently updated when NBET enters into a new power purchase agreement with GENCOS/IPPS

SCHEDULE 6 – Insurance Coverages.

- Commercial/General Liability: Coverage amount is yet to be provided.
- Workers Compensation and Employers Liability: Coverage amount is yet to be provided

SCHEDULE 8 - Schedule of Disco Shares:

- This is required to be populated and subsequently updated once PPA is signed between GENCOS/IPPS and NBET

9.3.3 Action Plan to Address Gaps

- NBET still expects the DisCos to put in place the required security cover before the Vesting Contracts can become effective.
- It is also expected that NBET will populate all the schedules under the Vesting Contracts before the commencement of TERM

10 TCN CONTRACTS

10.1 Grid Connection Agreements between TCN and DisCo/GenCo

10.1.1 TEM Requirement

- DisCos and GenCos execute Grid Connection Agreements with TCN.
- Grid Code Part 2, Section 4.3.1. stipulates that for directly connected units, data relating to the Power Station, both current and forecast shall be provided to the TSP. Such data is inclusive of output data and other rated parameter data (rated MVA, rated MW etc). The same goes for distribution networks connected directly to TCN infrastructure.
- All operational communication concerning the connection shall be in accordance with provisions of the Grid Code with each party expected to appoint Safety Coordinators.
- Characteristics of each unit within a generating plant should be attached as schedule to the Connection Agreement. In the same vein, all distribution feeders directly connected to the transmission network should have the injection capacities in the schedule. It is also desirable for the length of such distribution lines to be in the schedule too.

10.1.2 As-is State

- These Agreements have been signed, albeit, in a generic form. For the GenCo's some schedules have not been duly completed. For Disco's the schedules attached, where there is, are parameters of 132kV and 33kV infrastructure within the Transmission switchyard. There is absolutely no schedule attached from the Disco.
- Connection Agreement Clause 3.2.2: The Company hereby grants its consent to TCN's Connection Equipment remaining on premises owned or occupied by it at the Connection Site, to the extent required to establish and maintain the interface connection between the Company's System and TCN's Transmission Network System, until this Agreement is terminated in accordance with Clause 7. Although this Agreement has been signed, TCN is not comfortable with the suggested boundary; likewise the Discos too.
- Safety coordinators have not been appointed.

10.1.3 Action Plan for TEM

- Where documentations are available, all parameters should be duly filled out in the schedules before the Agreements can come into effect. This is both for Grid protection and planning purposes. Where there are no documentations, plant operators should liaise with the SO for studies and tests to determine the actual capabilities of the plant to provide such services.
- Schedules attached to the DisCo Connection Agreements have not been fully filled out; this has to be done before Agreements can be operational and TEM declared. Evidently missing in the schedules are the current injection (33kV) capacities of the various feeders emanating from the connection points. These capacities are important for both planning and relay coordination (system reliability) purposes.
- TCN is not comfortable with the interface boundary with the Disco's; neither are the Discos. The general consensus is that the boundary should be after the 33kV bus bars, at the interface metering points. These boundaries should therefore be adjusted, going into TEM. The boundary between TCN and the GenCos is much more manageable.

10.2 Ancillary Services Agreement between TCN and GenCo

10.2.1 TEM Requirement

- GenCos execute Ancillary Services Agreements with TCN. Ancillary Services include spinning reserve/frequency control, voltage support and black start.
- Every generating plant statutorily offers voltage support in accordance with characteristics/capabilities of their units. It is only when they need/have to do more as instructed by the SO that the need to pay arises.
- In accordance with provisions of the Grid Code, all GenCo's are expected to register the current, realistic characteristics of their units with TCN/SO with particular reference to ancillary services capability. Ancillary Services Agreement should therefore be based on need for provision of more than this minimum level. Proper metering, voice and data communication infrastructure should be in place between the GenCos and TCN/SO.
- TCN/SO is expected to regularly perform ancillary services scheduling and inform all stakeholders.

10.2.2 As-is State

- During a previous TCN effort, only three GenCos were identified as capable of providing spinning reserves (frequency support). These stations are Kainji, Egbin and Delta. At present, only Kainji offers some limited reserves, while Delta concentrates on offering black start. According to the plant operators, the black start facility in Delta has recently been showing signs of fatigue and may eventually give up. The gap here is substantial and other power plants have to be encouraged to join in the provision of such services too.
- It is general knowledge that Shiroro is equipped with the facility to provide voltage support. The schedules attached to the Agreements are not complete in some cases. Where complete, however, they are as built characteristics of the units and no longer realistic. Where schedules are attached, the characteristics therein are as built and not as currently realistic.
- As earlier mentioned, characteristics of each unit within a generating plant should be attached as schedule to the Connection Agreement, including capabilities for ancillary services. This has not been done in all the plants.

10.2.3 Action Plan to Address Gaps

- Characteristics of each unit within a generating plant should be attached as schedule to the Connection Agreement, including capabilities for ancillary services. This has not been done in all the plants. Current realistic characteristics should be verified by the SO. Machineries should quickly be put in place to address this gap.
- Where realistic characteristics are not available, studies should quickly be commissioned to establish same.
- The voltage support facilities at Shiroro should be commissioned and deployed appropriately. Operations planning should henceforth include computation of daily ancillary services requirement, schedule deployment of such services and document properly. Furthermore, until SCADA is fully available, efficient documentation processes should be put in place to accurately report instructed deployment of ancillary services.

11 COMPLIANCE WITH CPS FOR INITIATION OF TEM, AS SHOWN IN MARKET RULES

11.1.1 TEM Requirement

The Conditions Precedent for the Transitional Stage are shown in the Market Rules Appendix 2.

11.1.2 As-is State

Table 11.1 shows a factual and qualitative assessment of the status of attainment of the required Conditions Precedent for TEM, as listed in the Market Rules.

Table 11.1: Status of Attainment of Conditions Precedent for TEM

CP for TEM:	Status	Comments
(a) passage of the Electric Power Sector Reform Act		Condition has been met.
(b) establishment and commencement of operations of the Commission;		Condition has been met.
(c) development, implementation and testing by the System Operator, of the systems and procedures required to implement the Grid Code;		As described in this report, some SO systems and procedures required for TEM, e.g. tracking of GenCo Available Capacity, are not present, and current rate of improvement appears inadequate for expected schedule for initiation of TEM.
(d) development, implementation and testing by the Market Operator, of the systems and procedures to implement the Market Rules for the Transitional Stage;		As described in this report, some MO systems and procedures are suboptimal and improvements are needed.
(e) approval of the Grid Code and the Market Rules;		Condition has been met.
(f) formalisation of the trading arrangements (vesting contracts) between the companies that will participate in the Transitional Stage Market;		As described in this report, the Vesting Contracts and PPAs are not yet in effect. The PHCN legacy PPAs have not yet been novated to NBET.
(g) publication by the Commission, of a list prepared to the best of its knowledge, stating in respect of the initial market, the names and addresses of each Licensee, including interim Licensees, and of each other person then entitled to become a Participant at the date of publication, subject, in each case, to compliance by such Licensee or other person, with all relevant procedures and Legal Requirements;		Condition has been met.
(h) publication of the initial transmission Usage Charge by the Commission;		Condition has been met.
(i) publication of the initial System Operation and Market Administration Charge by the Commission;		Condition has been met.

CP for TEM:	Status	Comments
(j) constitution of the initial Dispute Resolution Panel, and the Initial Stakeholder Advisory Panel;		The leadership of Dispute Resolution Panel has been formally appointed. The Stakeholder Advisory Panel is in place. Related processes are still under development.
(k) approval of the Grid Code by the Minister and implementation of the provisions of the Grid Code; and		Condition has been met.
(l) approval of the Market Rules by the Minister and implementation of the provisions of the Market Rules applicable to the Transitional Stage.		Condition has been met.

12 SHADOW TRADING DURING THE LEAD UP TO DECLARATION OF TEM

12.1 Overview of Shadow Trading

A testing period is needed during the lead up to declaration of TEM to ensure the readiness of both new and existing systems and procedures for managing trading. Shadow Trading is the process for full scale testing and monitoring of the processes and systems for collection of both metered and non-metered data used in settlement, invoicing, revenue collection, payments and periodic reconciliations. Shadow Trading is necessary because delays and errors in implementing complex systems are inevitable, and if these interfere with proper cash flows they will reduce the credibility of TEM. Shadow trading may allow the opportunity for prompt, pro-active corrective action prior to or upon TEM implementation, as well as identification of the need for long term modifications.

The purpose of testing is to ensure that Day 1 processes and systems are ready for commercial operations, and that other systems that are in the pipeline but not yet ready for Day 1 are also reviewed on a timely basis. The essential elements of shadow trading are: (i) a realistic, complete test of Day 1 Systems, using the procedures, protocols, equipment, systems and personnel that will be used in actual trading, and (ii) protection of market participants from economic consequences in the event of delays and errors in design or implementation.

With the implementation of TEM, NBET will become an essential intermediary between Market Participants. This requires that a number of new systems be put in place by market participants, and creation of new interfaces.

12.2 Systems and Procedures to be Tested during Shadow Trading

Testing initially will focus on the readiness of existing systems used by the MO and SO to manage trading. All shadow processes and systems should reflect the terms and conditions in contracts, agreement and tariffs, i.e.: NBET's PPAs, VCs and direct charges; as well as those arrangements to be handled directly by MO on an ongoing basis (market participation agreements, charges for TSP, MO, SO and NERC, and ancillary services charges).

NBET's systems and processes for trading should be tested as they are rolled out. For example, NBET can prepare its own invoices to DisCos and review invoices submitted by GenCos/IPPs, even while these functions are still officially handled by MO.

The sections below provide a framework for testing of systems and processes during the lead up to Day 1 of TEM.

12.2.1 Meter Data Collection and Generation Availability Tracking

Testing will involve verifying that adequate metering is in place, metering codes and procedures are being observed and the data acquisition process is efficient and accurate for measuring contract quantities delivered by GenCos and received by DisCos.

New processes to be used by the SO to track generators' nominations and despatch quantities used in the determination of Monthly Available Capacity of the GenCos and load allocation to the DisCos will also be tested as such new processes are rolled out. In the absence of SCADA, the SO/MO will need to take manual hourly readings of GenCo grid meters for capacity availability tracking purposes. This will also enable the MO to get the meters to be capable of integrating the hourly readings of the real time MW values, average then integrated hourly readings over the month and

store up for retrieval as a single quantity. Such procedures are not in place at present and must be developed during the Shadow Trading period.

12.2.2 Invoicing

The testing period will involve verifying that the transactions are properly priced according to contractual terms and conditions in the PPAs and VCs for purposes of creating the invoices issued by MO/NBET, and that invoicing procedures shown in the PPAs, VCs and Market Rules are observed.

During Shadow Trading, Successor GenCos should issue invoices to NBET, MO and SO (for ancillary services). This invoicing function is not currently in place at the Successor Companies, in contrast to the IPPs, which have been issuing invoices to the MO. The involved parties will need to work out new procedures for reconciling the GenCos' invoices with the MO's settlement statements and the SO/MO's tracking system for generator capacity availability.

12.2.3 Revenue Collection

In the immediate term, the testing will verify that the existing infrastructure, processes and systems used by the MO for revenue collection from DisCos are adequate for commercial operations under TEM. If NBET introduces its own system for revenue collection, it will also need to be tested on a timely basis.

12.2.4 Payments

Until such time as the GenCo PPAs and VCs are fully in effect, e.g. CPs in such agreements have been met, the MO will continue to be responsible for payments rather than NBET. The testing period will involve verifying that the MO makes payments according to the waterfall shown in the Interim Market Rules.

12.2.5 Reconciliation

The testing period will involve verifying that monthly and annual reconciliations are done according to applicable rules and procedures:

- Energy and capacity balances
  - Sent out versus received
  - Imbalance of load drawn by DisCos vis-à-vis load allocation
- Revenue balance (i.e. total revenues in vis-à-vis total payment obligations)

12.2.6 Disputes

MO processes for submission and resolution of complaints should be aligned with rules and procedures and tested during Shadow Trading. NERC should operationalize its procedures related to market disputes during Shadow Trading.

12.3 Role of NBET during Shadow Trading

During the testing period, NBET may begin the process of assuming new responsibilities in market operations, as described in the following sections. Testing will involve verifying that NBET processes and systems, operating initially in shadow mode, are fully ready for live operations.

12.3.1 Invoicing

NBET can prepare shadow invoices to the DisCos based on the quantities provided by the Market Operator. This will provide a test period for NBET to refine its internal procedures for the

invoicing and reconciliation functions, as well as its coordination and interfaces with the MO for such functions.

12.3.2 Revenue Collection and Payments

If agreed during the Shadow Trading period, NBET may set up and test its own banking arrangements for revenue collection from DisCos and payments to GenCo. Under current plans being developed by NBET, all revenue inflows from DisCos for capacity, energy and NBET charges are to be made to NBET Clearing Account(s) controlled by a Payment Agent. The banking arrangements will also integrate payments to GenCos and IPPs. Since the Payment Agent will control cash flows, Payment Agent procedures will need to be tested under real market conditions before going live. The clearing account must be opened, directions must be prepared and approved for payments from DisCos to the Clearing Account, and details of payments to GenCos must be established.

12.3.3 Reconciliation

If agreed during the Shadow Trading period, NBET will assume a role in the revenue reconciliation process in coordination with the MO. However, it is expected that reconciliation of capacity and energy quantities will continue to be the sole responsibility of the MO.

12.3.4 Disputes

The role of NBET vis-à-vis MO in dispute resolution needs to be worked out and agreed between the parties and NERC. NBET should operationalize its procedures related to market disputes during Shadow Trading.

12.4 Shadow Trading Working Group

A working group consisting of MO, SO, NBET, NERC, NIAF and Nexant should be set up to plan and oversee Shadow Trading during the Interim Period. There should be a role for Market Participants to provide constructive feedback. The initial task of the working group is to monitor the settlements and payments process for the month of October 2013, for which the payment cycle should be concluded by end of November 2013.

For questions regarding this publication, please contact Erin Hammel (ehammel@naruc.org) or Bevan Flansburg (bflansburg@naruc.org).

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